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PACIFIC GAS AND ELECTRIC COMPANY

**APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY TO
RECOVER HELMS UPRATE COSTS**

REVISED PREPARED TESTIMONY

(PUBLIC VERSION)



PACIFIC GAS AND ELECTRIC COMPANY
APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY TO
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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

POLICY AND OVERVIEW

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
POLICY AND OVERVIEW

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 1**
3 **POLICY AND OVERVIEW**

4 **A. Introduction**

5 This chapter provides an overview of Pacific Gas and Electric Company's
6 (PG&E) Application for approval of the Helms Uprate Project (Uprate) and
7 discusses the rationale for why it is a cost-effective solution to California's need
8 for additional long-duration energy storage to support a clean and reliable grid.

9 **B. Overview of the Proposed Uprate**

10 As more fully described in Chapter 2 of this testimony, PG&E has identified
11 a unique opportunity to increase the nameplate generation capacity of PG&E's
12 existing Helms Pumped Storage Plant (Helms) by 150-180 megawatts as part of
13 needed lifecycle maintenance work on the facility. If approved as proposed in
14 this testimony, PG&E targets completing the Uprate between 2029 and 2031,
15 focusing on uprating one of each of Helms' existing three generating/pumping
16 units in each of those years. Because many of the major generation equipment
17 components at Helms are due for lifecycle replacement in the next 10 years
18 (Lifecycle Replacement Work), the Uprate would achieve improved unit design
19 and increased nameplate ratings in an efficient manner at a modest and
20 cost-effective incremental cost to planned work.

21 **C. Summary of Cost Forecast and Associated Cost Recovery Request**

22 As detailed in Chapter 2, PG&E currently estimates that the Uprate will
23 result in capital expenditures of \$462 million (nominal). However, removing from
24 that total forecast the estimated cost that PG&E would incur to undertake the
25 otherwise needed Lifecycle Replacement Work and further subtracting an
26 anticipated 30 percent federal investment tax credit, the net cost forecast to
27 obtain the incremental capacity associated with the Uprate is approximately
28 \$27 million.

29 As detailed in Chapter 4 of this testimony, PG&E proposes to establish an
30 initial cap on the amount that it would be authorized to recover for the Uprate
31 without further reasonableness review. PG&E requests that this cap be set at
32 the forecast of \$462 million, which includes the minimum contingency

recommended by industry standard practices for a project of this level of project design maturity.

The use of a minimum contingency creates an aggressive target for cost containment. However, the Uprate is being submitted for California Public Utilities Commission (Commission) review at a particularly early stage of project development in order to maximize the opportunity to capture the unique nature of the opportunity, including the desire to integrate the capacity increase into the Lifecycle Replacement Work and the current availability of tax credits. The lack of interconnection studies by the California Independent System Operator (CAISO) and the need for approval of a license amendment for the Uprate by the Federal Energy Regulatory Commission (FERC) create significant uncertainties regarding project costs that are largely outside of PG&E's control. PG&E will not likely know the outcome of these processes for several years, which would be beyond the date by which PG&E needs authority to proceed with long-lead time procurement and project development activities. To address these uncertainties while allowing PG&E to realize this opportunity and maintaining an aggressive cost control cap, PG&E requests the ability to submit one or more Tier 3 Advice Letters (AL) in the future to seek increases in the initial cost recovery cap due to future forecasted increases in costs from those forecasted in this testimony due to CAISO interconnection or FERC license amendment requirements. PG&E would need to include in any such AL a demonstration that the Uprate remains cost-effective with the proposed increases in the cost recovery cap.

Beyond this Tier 3 AL process for these certain categories of contingencies, PG&E proposes a more general mechanism for seeking reasonableness review of any costs above the cost recovery cap that it actually incurs in the Uprate. Specifically, PG&E proposes to track any such incremental costs in a memorandum account, and PG&E could only recover such incremental costs following reasonableness review of those costs in a separate application filed with the Commission.

D. Need and Cost-Effectiveness of the Uprate

The Uprate is a cost-effective approach to provide additional long-duration energy storage to help integrate the grid's rapidly increasing volumes of

1 intermittent renewable generation, mitigate ongoing grid stability challenges, and
2 provide resiliency during periods of peak demand and grid emergencies.

3 As economic, regulatory, and legislative changes bring about a rapid
4 evolution of the California grid, energy storage of all types becomes more
5 important to help maximize the value of the greenhouse gas-free, yet
6 intermittent, renewables that are necessary on the path towards
7 decarbonization. Whereas most of the energy storage being deployed in
8 California are shorter duration storage technologies, like lithium-ion batteries,
9 Helms' pumped storage technology represents an opportunity for the
10 Commission and PG&E to add complementary long-duration storage that can
11 help bridge multi-day and seasonal grid supply shortages. Chapter 3 of this
12 testimony discusses the ways in which the Uprate is highly aligned with the
13 findings of the Commission-approved Integrated Resource Plan scenarios and
14 long-term procurement needs.

15 As further detailed in Chapter 3, the Uprate is a cost-effective approach to
16 procuring incremental long-duration storage for both PG&E's bundled portfolio
17 need and broader system-wide needs. In particular, the Uprate competes
18 favorably with other storage procurement opportunities and market benchmarks
19 for energy storage generally, and long-duration storage in particular. These
20 results are in part, the result of the unique nature of the opportunity: PG&E can
21 incorporate the increase in capacity with planned Lifecycle Replacement Work
22 and expects to receive an investment tax credit due to the Uprate.

23 **E. Cost Allocation**

24 As further described in Chapter 4, PG&E proposes to recover all
25 above-market costs associated with the Uprate through the Power Charge
26 Indifference Adjustment via two separate vintages. First, PG&E proposes that
27 above-market costs associated with the extant capacity of Helms continue to be
28 recovered through the Legacy Utility Owned Generation Subaccount, which
29 records and recovers the above market costs associated with adopted revenue
30 requirements related to PG&E-owned generation installed before 2002
31 ("Legacy UOG"). Second, PG&E requests that above-market costs associated
32 with the proposed incremental capacity included in the Uprate be recovered via
33 a new vintage subaccount.

1 **F. Testimony Overview**

2 The remaining chapters of this testimony provide additional detail to support
3 the Uprate. The remaining chapters are organized as follows:

- 4 • Chapter 2: Project Scope, Cost Forecast, and Timeline;
5 • Chapter 3: Project Need, Benefits, and Cost-Effectiveness; and
6 • Chapter 4: Ratemaking Proposal and Revenue Requirements.

7 **G. Conclusion**

8 The Uprate advances the State’s affordability, grid reliability, and climate
9 goals. When compared to other energy storage alternatives, the project is cost
10 competitive and extremely viable. Finally, the Uprate brings much-needed
11 technological diversity to the State’s energy storage portfolio.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
PROJECT SCOPE, COST FORECAST, AND TIMELINE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
PROJECT SCOPE, COST FORECAST, AND TIMELINE

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 2**
3 **PROJECT SCOPE, COST FORECAST, AND TIMELINE**

4 **A. Introduction**

5 The purpose of this chapter is to describe the scope and timing of the
6 proposed Helms Uprate Project (Uprate), to present the cost forecast for the
7 Uprate (Uprate Cost), and to address safety considerations arising from the
8 Uprate.

9 **B. Project Objectives**

10 The objective of the Uprate is to increase the generation capacity of
11 Helms Pumped Storage Hydroelectric Power Plant (Helms) by
12 150-180 megawatts (MW), increasing the nameplate total capacity from
13 1,212 MW up to 1,392 MW. The corresponding net capacity increase at the
14 point of interconnection is estimated to be 129-156 MW.¹ The Uprate will also
15 seek to increase pumping capacity proportional to the increase of generation
16 capacity. The target online dates are end of year 2029-2031 (1 unit per year)
17 with an estimated earliest date of Resource Adequacy Full Capacity
18 Deliverability Status eligibility of end of year 2030.

19 There are three main drivers for proposing the Uprate now. The first driver
20 is to support the State of California's long-duration energy storage procurement
21 goals. Long-duration energy storage is needed to ensure grid reliability while
22 meeting increasing electricity demand.² Second, most of the major generation
23 equipment components at Helms are due for lifecycle replacement in the next
24 10 years, presenting a unique opportunity to undertake the Uprate in a
25 cost-effective manner at the same time. Third, the Uprate is designed to take
26 advantage of federal tax incentives under the Inflation Reduction Act.

1 The net capacity increase at the point of interconnection is less than the unit nameplate capacity increase due to transformer and transmission line losses between the unit and the point of interconnection at Gregg Substation in Fresno, California, approximately 60 miles from Helms.

2 The broader need for the project and the ways in which it is expected to support state policy goals is more fully discussed in Chapter 3 of this Testimony.

C. Project Scope

At a high level, the Uprate project scope includes replacement of turbine, generator, and transformers, as well as replacement of balance of plant components. Additionally, it is anticipated that interconnection requirements will trigger substation and/or transmission upgrades. Studies and preliminary engineering results from engineering consultants and Original Equipment Manufacturers (OEM) of the turbine and generator have contributed significantly to the current understanding of the required scope to achieve the Uprate.

1) Turbine

- a) Replacement of the turbine is necessary to allow higher volumes of water to flow through the units. The turbine is a limiting factor to how much increase in generation and pumping capacity the Uprate can achieve.
- b) Based on the OEM – Hitachi Turbine Study and Pumping Study (Attachments A and B), the scope of work for the turbine includes replacement of the runner and replacement or modification to the wickets, servo, operating ring, discharge ring, draft tube, headcover, piping, shaft, and wear parts. Each of these, except for the draft tube, are manufactured components. Modifications to the draft tube involve expanding the rock chamber and replacement of the draft tube liner. The extent of modifications to the rock chamber will be an important factor as to how much increase in capacity can be achieved.
- c) The next phases of turbine design will focus on determining the optimal balance between an increase in generation capacity and an increase in pumping capacity. Ideally, generation and pumping capacities would increase by an equivalent ratio to today's capacities. This is because Helms already maximizes pumping in the least cost hours of the day. If Helms were to need to pump longer each day to return the water for generation, it would have to pump during higher cost hours, making it less beneficial. For purposes of the cost-effectiveness calculations described in Chapter 3, PG&E examined two capacity increase scenarios which bookend the anticipated capacity increase outcomes of the Uprate.

1 2) Generator

- 2 a) The generator scope of work will be partially dependent on the uprated
3 turbine design. The generator will need to be capable of an output that
4 aligns with the maximum turbine output. Based on the OEM – Voith
5 Generator Study (Attachment C) and the OEM – GE Rotor Study
6 (Attachment D), the scope of work for the generator includes
7 replacement of the stator windings and generator core for Unit 1 and
8 Unit 3, replacement of the rotor poles for all three units, and
9 modifications to the spiders. Unit 2 generator had its stator windings
10 replaced more recently and the current design can support the proposed
11 Uprate increase in generation.
- 12 b) Replacement of the stator windings, core, and rotor poles are necessary
13 to increase the current carrying capability. Modification of the spider is
14 necessary to withstand the increase stresses of greater generation
15 output.

16 3) Transformer

- 17 a) The transformer scope of work includes replacement of all 10 main
18 step-up transformers (3 for each unit, plus a spare). Depending on the
19 design of the uprated transformers, additional modifications within the
20 transformer gallery may be required, including replacement or
21 modification of heat exchangers, fire protection, and transformer blast
22 protection system.

23 4) Balance of Plant

- 24 a) The balance of plant scope includes all other Helms components that
25 require an increased rating to achieve the Uprate output. Based on
26 Engineering Consultant – Black and Veatch Helms Uprate Feasibility
27 Study (Attachment E), the balance of plant scope includes replacement
28 of the exciter components, isolated phase bus, reverse disconnect
29 switches, 230 kilovolt (kV) cables, and possibly other minor balance of
30 plant components. Each of these components will need to be uprated to
31 handle the increase in electrical current.

1 5) Interconnection Requirements

- 2 a) It is anticipated that interconnection for the greater nameplate capacity
3 created by the Uprate will require replacement or installation of
4 substation and/or transmission related components. The existing
5 interconnection facilities for Helms include two 230 kV generation tie
6 transmission lines that connect the Helms Switchyard to
7 Gregg Substation and two circuit breakers with associated switches in
8 Gregg Substation.
- 9 b) An Interconnection Study request was submitted to the California
10 Independent System Operator (CAISO) in March 2023. The request
11 was included by CAISO in Cluster 15 of its study process. The Uprate
12 Study is slated to begin in April 2024 and is anticipated to take two to
13 three years to complete. The Study will identify modifications to the
14 electric grid that are required to accommodate the Uprate. The detailed
15 scope of this portion of work is unknown right now, but a placeholder
16 cost of \$12.17 million has been included in the Uprate Cost to cover
17 modifications to non-reimbursable Interconnection Customer's
18 Interconnection Facilities.³ This placeholder does not include any cost
19 for Network Upgrades,⁴ as those costs are typically reimbursed by the
20 Transmission Operator. As described in Chapter 3, a separate
21 placeholder cost of \$13.1 – 15.8 million has been included in the Net
22 Market Value analysis to represent the potential Network Upgrade costs.
23 Since the interconnection costs are not currently known, PG&E

3 The CAISO tariff defines Interconnection Customer's Interconnection Facilities as follows:

 "All facilities and equipment, as identified in Appendix A of the Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the CAISO Controlled Grid. Interconnection Customer's Interconnection Facilities are sole use facilities." CAISO Tariff, App. A.

4 The CAISO tariff defines Reliability Network Upgrades in relevant part as follows:

 "The transmission facilities at or beyond the Point of Interconnection identified in the Interconnection Studies as necessary to interconnect one or more Generating Facility(ies) safely and reliably to the CAISO Controlled Grid, which would not have been necessary but for the interconnection of one or more Generating Facility(ies), including Network Upgrades necessary to remedy short circuit or stability problems, or thermal overloads." CAISO Tariff, App. A.

proposes to submit a Tier 1 Advice Letter within 30 days of its receipt of a final Phase 2 Interconnection Study, or other similar interconnection study, that informs the California Public Utilities Commission (CPUC or Commission) of the estimated cost of all interconnection upgrades required for the Helms Uprate project, including Network Upgrade costs. Please see more details regarding the placeholder for interconnection costs in Section F – Cost Forecast, below.

D. Relationship to Regular Maintenance and Replacement of Existing Helms Capital Components

Many of the major generation equipment components at Helms are due for lifecycle replacement in the next 10 years (Lifecycle Replacement Work). Specifically, the turbine runner and runner mating components, the generator stator windings and generator core for Unit 1 and Unit 3, and the main step-up transformers are all due for routine lifecycle replacement.⁵ The Uprate is a unique opportunity for improved unit design and increased nameplate ratings of the turbine, generator, and transformer at an incremental cost to this planned Lifecycle Replacement Work.

If the Uprate is not approved, a significant portion of the work will still need to be performed as routine lifecycle replacement, but without an increase to rated capacity. In the event that the Uprate does not move forward, this Lifecycle Replacement Work will be proposed in PG&E's next (test year 2027) General Rate Case (GRC) cycle, with an implementation target of 2030-2032 (one unit per year).

⁵ If the turbines are not replaced, more frequent and longer maintenance outages would be needed to address turbine cracking. Eventually, the turbine vanes or other components can become so degraded that the unit can no longer operate. If the generators are not rewound, more frequent and longer maintenance outages would be needed to address generator winding hot spots. A derate of the unit is likely if sections of windings cannot be repaired and must be cut out. If the transformers are not replaced, the likelihood of catastrophic failure increases with time. At some point, the transformer will fail to pass condition testing and would most likely be removed from service.

1 **E. Relationship to Already Authorized Work**

2 This section describes how the Uprate relates to work proposed and work
3 authorized in the 2023 or earlier GRCs and to PG&E's upcoming 2027 GRC.

4 1) 2023 GRC

- 5 a) In response to CPUC's identified need for incremental long-duration
6 energy storage, PG&E was evaluating ways to move forward with a
7 project to uprate the existing units at Helms during the 2023 GRC
8 period. PG&E proposed to establish the Helms Capacity Memorandum
9 Account (HCMA), effective January 1, 2023, to record costs in
10 connection with the uprate of the three existing units at Helms. Such
11 costs would have included planning, engineering, permitting, equipment
12 upgrades, construction, commissioning, testing, and other reasonable
13 expenditures to implement the Uprate.
- 14 b) As part of a stipulation reached during the CPUC's review of PG&E's
15 2023 GRC application,⁶ PG&E agreed to withdraw its request to
16 establish the HCMA and The Utility Reform Network (TURN) agreed that
17 PG&E may seek recovery of reasonable costs associated with the
18 Uprate if the project is cost-effective and PG&E seeks approval for the
19 project in a separate CPUC proceeding.⁷ The CPUC approved the
20 Energy Supply Stipulation in Decision (D.) 23-11-069.⁸
- 21 c) Accordingly, none of the Uprate scope of work was included in the list of
22 forecasted capital expenditures in the 2023 GRC.

6 A.21-06-021, PG&E GRC Opening Brief (Nov. 4, 2022), App. E (Stipulation of TURN and PG&E on Energy Supply Issues).

7 *Id.*, App. E, pp. E-3 to E-4; *Id.* p. 624. See also *id.*, p. 615 ("Unless otherwise directed by the Commission: (1) new utility-owned generation capacity projects greater than 5 MW; or (2) new utility-owned generation capacity projects that are forecast to exceed \$20 million; or (3) utility owned generation projects that increase facility nameplate capacity by greater than 10 percent; or (4) utility-owned generation projects that increase facility nameplate capacity that are forecast to exceed \$20 million, must be proposed in the Integrated Resource Plan proceeding or other proceeding that authorizes procurement (including, but not limited to, the Renewable Portfolio Standard Proceeding, or Resource Adequacy Proceeding or separate application), before requesting funding for the project in a GRC. This provision does not apply to reliability or efficiency projects (such as hydro turbine runner replacement or step-up transformer replacement.").

8 D.23-11-069, p. 508.

1 2) Prior GRC Proceedings

- 2 a) PG&E has examined work approved in GRCs prior to 2023 and has not
3 identified any authorized capital project that is the same work for the
4 same purpose as the Uprate. Accordingly, the Uprate scope is not
5 seeking rate recovery for work previously authorized.
- 6 b) In PG&E's past GRC proceedings, there were projects that might initially
7 appear to be the same or similar work to that proposed within the scope
8 of the Uprate. For example, the generator rotors were replaced on all
9 three units in 2015, and in the Uprate PG&E is proposing replacement of
10 the rotor poles. Rotor pole replacement is a much smaller scope than
11 rotor replacement. If the Uprate is not approved, rotor pole replacement
12 would not be needed. Therefore, its costs are not included in the
13 comparative lifecycle cost estimate.
- 14 c) Another past project that may appear duplicative of work in the Uprate
15 scope is the replacement of the turbine shaft seal that occurred in 2020
16 on Unit 3 and 2022 on Unit 1. PG&E expects to again replace the
17 turbine shaft seal as part of the Uprate, but the purpose is not routine
18 lifecycle maintenance as with the prior GRC-approved project. Rather,
19 the turbine shaft seal would be replaced as a part of the Uprate project
20 due to the engineering best practice to replace all wear-related parts
21 that are disassembled and reassembled because of the turbine
22 unstacking or because it requires redesign to mate properly with the
23 new turbine.

24 3) Future GRC Proceedings

- 25 a) The 2027 GRC will include additional Helms lifecycle maintenance work
26 that is not included in the Lifecycle Replacement Work estimate
27 contained within this application. If the Uprate is not approved prior to
28 preparation of PG&E's 2027 GRC Application, the Lifecycle
29 Replacement Work contained within this application will also be included
30 in the 2027 GRC. PG&E would withdraw its request for authorization of
31 the Lifecycle Replacement Work in the 2027 GRC if it was subsequently
32 and fully approved as part of this Application.

1 **F. Regulatory and Interconnection Approvals Required**

2 There are three core regulatory approval processes before three different
3 authorizing entities for the Helms Uprate Project, each of which is described
4 more fully below. The purpose of this section of testimony is to describe how the
5 CPUC's ratemaking approval, as requested in this Application, is expected to
6 relate to the approvals that PG&E will seek from the Federal Energy Regulatory
7 Commission (FERC) and the CAISO.

8 1) CPUC Approval

9 a) PG&E is seeking CPUC approval to recover the incurred costs of the
10 Uprate in rates, up to a cap based on the forecast, as further and more
11 specifically described in Chapter 4 of this Testimony. PG&E needs
12 approval now to implement the Uprate to align with the required
13 Lifecycle Replacement Work, take advantage of the Investment Tax
14 Credit (ITC)⁹ opportunity, and to help meet California's need for
15 long-duration energy storage. Waiting to submit an application until the
16 project is further developed or until the interconnection study is complete
17 would delay required Lifecycle Replacement Work, risking unit outages
18 if equipment fails, and could jeopardize the ability to take advantage of
19 the ITC.

20 2) FERC Approval

21 a) FERC has exclusive permitting jurisdiction over the Uprate pursuant to
22 the Federal Power Act, with the potential exception of any upgrades
23 needed to CPUC-jurisdictional distribution facilities.¹⁰ FERC will need
24 to approve an amendment to the existing Helms FERC License prior to

9 The ITC opportunity is further described in Section G.2.b of this Chapter.

10 PG&E is not currently aware of any such needed upgrades to CPUC jurisdictional facilities. However, PG&E will not be able to rule out the possibility of any such upgrades until the CAISO completes its interconnection studies. To the extent any such additional CPUC approvals are necessary pursuant to the CPUC's General Order 131, PG&E will file separately for approval of those upgrades.

beginning construction of the Uprate. PG&E currently expects to apply for a “Non-Capacity Amendment”¹¹ (FERC License Amendment).

- b) The FERC License Application is planned to be filed after the CPUC Application because it will allow more time for greater definition of scope. Greater definition of scope is needed to confirm PG&E’s initial assessment that the Helms Uprate meets the criteria for a Non-Capacity Amendment. There is a potential for FERC approval to lead to additional scope/costs not anticipated in the cost forecast presented in this chapter. As further described in Chapter 4, PG&E is asking for approval to seek CPUC review of any such incremental FERC License Application costs not included in the current capital cost forecast via Advice Letter.
- c) PG&E’s expected schedule for obtaining the FERC License Amendment is as follows:
 - i) April 2024 – PG&E finalizes initial draft of the FERC License Amendment.
 - ii) May 2024 – PG&E initiates pre-filing stakeholder review of the draft FERC License Amendment with the following agencies and key stakeholders for a 60-day review:
 - 1. United States Department of Agriculture, Forest Service, Sierra National Forest (Forest Service);
 - 2. United States Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service;
 - 3. United States Department of the Interior, Fish and Wildlife Service;
 - 4. United States Department of the Interior, National Parks Service;
 - 5. United States Environmental Protection Agency;

¹¹ The Uprate likely requires a non-capacity-related amendment to the existing FERC license, because the amendment request meets all of the following criteria: (1) the Uprate would increase the installed nameplate capacity of the Helms project; (2) the increase in installed capacity has not been previously authorized by FERC; and (3) the increase in installed capacity would be more than 2 megawatts (MW), but the Uprate would not increase Helms’ maximum hydraulic capacity by more than 15 percent. See 18 C.F.R. § 4.201(b).

6. California Department of Fish and Wildlife;
7. California State Water Resources Control Board (State Water Board);
8. California State Historic Preservation Officer; and
9. Native American Tribes.

iii) Compile comments from agencies and stakeholders (45 days).

iv) September 2024 – Target date for PG&E filing Non-Capacity License Amendment with FERC.

v) April 2025 – July 2026 – Target date for FERC issuance of FERC License Amendment.

d) PG&E will provide a draft amendment application to state and federal agencies for a 60-day consultation period. After the review period, PG&E will compile comments from state and federal agencies and provide them to FERC with the amendment application. FERC will most likely notice the application and allow another public review period. Based on public comments, FERC will determine if an Environmental Analysis (EA) or an Environmental Impact Statement (EIS) is necessary in order to comply with the National Environmental Policy Act (NEPA). FERC may also choose to mitigate potential environmental impacts in any order FERC issues regarding PG&E's license amendment application.

3) CAISO

a) CAISO will need to execute an amendment to the Helms Interconnection Agreement (IA) prior to putting the Uprate into service. In order to receive this IA amendment, the Uprate must be studied by CAISO under its applicable tariff provisions to determine what interconnection grid modifications are required to support the increased capacity (Interconnection Study). PG&E submitted an Interconnection Study request to CAISO in March 2023 to initiate this process. The CAISO has placed the IA amendment application into its cluster study process, as part of Cluster 15. Accordingly, the Interconnection Study is slated to begin in April 2024 and is anticipated to take two to three years to complete. Following the Interconnection Study results, any identified

1 grid modifications will need to be implemented prior to operating at an
2 increased capacity level.

- 3 b) The amended IA will describe the changes to the interconnection and
4 costs associated with those changes. PG&E has included some costs
5 in the current forecast for modifications that may be required, such as
6 substation breaker and switch replacements. The Interconnection Study
7 may reveal significant additional scope triggering the need to submit an
8 updated cost forecast. As further described in Chapter 4, PG&E is
9 asking for authorization to submit any such incremental,
10 non-reimbursable interconnection costs above those included in the
11 current capital cost forecast via Advice Letter.

12 **G. Cost Forecast**

13 The purpose of this section is to present PG&E's current forecast of the
14 costs expected to be incurred to complete the Uprate based on the scope and
15 other assumptions contained in PG&E's preliminary engineering studies. The
16 forecast is therefore conceptual and preliminary, corresponding to a Level 5
17 estimate using the Association for the Advancement of Cost Engineering
18 (AACE) Guidelines. Class 5 estimates are prepared based on limited
19 information (e.g., a very high-level investment objective) and consequently
20 acknowledge a wide range of potential actual outcomes.

21 A Class 5 estimate recognizes the significant uncertainties and risks
22 remaining in project development and design that require relatively large
23 contingencies in the forecasting process. For example, both the COVID-19
24 pandemic and the Ukraine conflict have resulted in recent and persistent market
25 fluctuations, creating risks for large capital projects that were not historically
26 present. As this is a technologically complex project, the AACE guidelines
27 indicate the need for, and PG&E has adopted, contingency amount of
28 50 percent or more.

29 The Class 5 estimate for the Helms Uprate is based primarily on input from
30 subject matter experts (Engineering and Project Management) and was
31 compared to historic cost benchmarking data from similar prior work at Helms,
32 where available. To increase confidence in the forecast, PG&E Generation
33 Strategy conducted an independent review of the initial subject matter expert
34 estimates to ensure completeness and consistency, and to ensure contingencies

were commensurate with the early-stage maturity of the Uprate design and development.

In the following sections, PG&E first presents a total forecast for the Uprate and then shows the estimated net cost of the Uprate after removing the estimated Lifecycle Replacement Work costs that would occur in absence of the Uprate, and anticipated tax credits.

1) Total Project Cost Forecast

a) The below table represents PG&E's current estimate for the Uprate, inclusive of 50 percent contingency on all project components (Uprate Cost). The Uprate Cost is approximately \$462 million in nominal dollars, which includes 2.5 percent annual escalation. All costs shown are expected to be capitalized.

**TABLE 2-1
UPRATE COST**

Helms Uprate - Powerhouse Scope (in Thousands)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
<i>Project Admin/Outage & Reg. Support (2023 \$'s)</i>	400	1,000	800	800	750	750	2,000	2,000	2,000	150	10,650
<i>Turbine (2023 \$'s)</i>	250	1,500	4,000	1,500	10,000	10,000	24,000	14,000	14,000	200	79,450
<i>Generator/Rotor (2023 \$'s)</i>	250	500	2,000	1,000	6,000	6,000	12,000	5,000	12,000	200	44,950
<i>Transformer GSU (2023 \$'s)</i>	100	100	2,500	500	11,000	11,000	18,000	7,000	7,000	100	57,300
<i>Balance Of Plant (2023 \$'s)</i>	200	200	2,000	2,000	9,000	9,000	21,000	12,000	12,000	200	67,600
Total Powerhouse Scope (2023 \$'s)	1,200	3,300	11,300	5,800	36,750	36,750	77,000	40,000	47,000	850	259,950
Escalated (2.5%) Total Capital	1,200	3,383	11,872	6,246	40,565	41,579	89,296	47,547	57,265	1,062	300,015
Contingency (50%) Capital	600	1,691	5,936	3,123	20,283	20,790	44,648	23,774	28,632	531	150,008
Total Powerhouse Scope - Capital (Nominal \$'s)	1,800	5,074	17,808	9,369	60,848	62,369	133,945	71,321	85,897	1,592	450,023
Helms Uprate - Interconnection Scope (in Thousands)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
<i>Interconnection Facility Modifications (2023 \$'s)</i>	150	0	0	0	0	250	1,500	5,000	0	0	6,900
Total Interconnection Scope (2023 \$'s)	150	0	0	0	0	250	1,500	5,000	0	0	6,900
Escalated (2.5%) Total Capital	150	0	0	0	0	283	1,740	5,943	0	0	8,116
Contingency (50%) Capital	75	0	0	0	0	141	870	2,972	0	0	4,058
Total Interconnection Scope - Capital (Nominal \$'s)	225	0	0	0	0	424	2,609	8,915	0	0	12,174
Helms Uprate Cost - Capital (Nominal \$'s)	2,025	5,074	17,808	9,369	60,848	62,793	136,554	80,236	85,897	1,592	462,197

2) Net Incremental Capacity Cost Forecast

a) Lifecycle Replacement Work Forecast

i) The below table represents the estimated cost for Lifecycle Replacement Work (Lifecycle Replacement Cost) if the Uprate project did not proceed. The Lifecycle Replacement Cost is approximately \$300 million in nominal dollars, which includes 2.5 percent annual escalation and 50 percent contingency. All costs shown are expected to be capitalized.

**TABLE 2-2
LIFECYCLE REPLACEMENT COST**

Helms Lifecycle Replacement Cost - Capital (in Thousands)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
<i>Project Admin/Outage Support (2023 \$'s)</i>	150	750	750	750	750	750	2,000	2,000	2,000	150	10,050
<i>Turbine (2023 \$'s)</i>	0	1,500	7,500	7,500	7,500	7,500	12,000	12,000	12,000	200	67,700
<i>Generator/Rotor (2023 \$'s)</i>	0	0	1,000	3,000	6,000	3,000	12,000	0	12,000	200	37,200
<i>Transformer (2023 \$'s)</i>	0	100	1,000	5,000	10,000	18,000	7,000	7,000	7,000	200	55,300
Total Lifecycle Replacement Cost (2023 \$'s)	150	2,350	10,250	16,250	24,250	29,250	33,000	21,000	33,000	750	170,250
Escalated (2.5%) Total Capital	154	2,469	11,038	17,937	27,437	33,921	39,227	25,586	41,212	960	199,941
Contingency (50%) Capital	77	1,234	5,519	8,968	13,718	16,961	19,613	12,793	20,606	480	99,971
Helms Lifecycle Replacement Cost - Capital (Nominal \$'s)	231	3,703	16,557	26,905	41,155	50,882	58,840	38,380	61,819	1,440	299,912

b) Tax Credits

- i) The federal Inflation Reduction Act of 2022 (Act) provides incentives for green energy in the form of tax credits. PG&E anticipates that new generation and storage capacity of pumped storage hydroelectric facilities will qualify for a credit under the Act. The anticipated tax credit, if secured, would significantly offset the cost of the Uprate. This makes the Net Incremental Capacity Cost of the Uprate, once both the estimated Lifecycle Replacement Cost and tax credit are netted from the Uprate Cost, very cost-effective for PG&E customers, as further described in Chapter 3. This tax credit only applies to the Uprate and would not apply to the Lifecycle Replacement Work if the Uprate is not approved.
- ii) The Act substantially changes and expands existing tax credits for renewable energy, including the existing Internal Revenue Code (IRC) Section 45, Production Tax Credit (PTC) and Section 48 investment tax credit (ITC). Beginning in 2025, the Act starts a shift from these credits which focus on the source of the clean energy or electricity to a focus on zero or low emissions from whatever the source (IRC Sections 45Y and 48E). The new provisions extend the ITC and PTC for eligible facilities on which construction begins before 2034.
- iii) The Act generally provides for a base credit of 6 percent, which can be increased by five times to 30 percent if the project meets prevailing wage and apprenticeship requirements. PG&E anticipates that new generation and storage capacity of pumped storage hydroelectric facilities will qualify for a 30 percent tax credit,

1 which is estimated to be \$135 million based on the Estimate
2 presented above. PG&E currently meets prevailing wage
3 requirements for internal labor and contractors. PG&E plans to
4 implement new processes to ensure that it can demonstrate its
5 compliance with the prevailing wage and apprenticeship
6 requirements under the ITC.

7 b) Net Incremental Capacity Cost

8 i) The Net Incremental Capacity Cost of \$27 million is a proxy,
9 illustrative calculation to show the incremental cost to customers to
10 Uprate Helms when compared the alternative of planned Lifecycle
11 Replacement Work that does not increase the capacity of the
12 units.¹² The Net Incremental Capacity Cost is calculated as follows:
13 Uprate Cost minus Lifecycle Replacement Cost, less the anticipated
14 tax credits. The tax credits will reduce the project rate base and
15 hence the overall revenue requirement collected from customers.
16 Please see Chapter 3 for more details.

TABLE 2-3
NET INCREMENTAL CAPACITY COST

Uprate Cost	\$462M
<i>Lifecycle Replacement Cost</i>	<i>-\$300M</i>
<i>30% Tax Credits</i>	<i>-\$135M</i>
Net Incremental Capacity Cost	\$27M

¹² PG&E refers to the Net Incremental Capacity Cost as a proxy and illustrative for two reasons. First, this calculation uses a hypothetical cost of undertaking the Lifecycle Replacement Work. Actual costs for that work could have been more or less than forecast. Second, this calculation simplifies for purposes of illustration how any realized ITC will actually be flowed through in the revenue requirement. The actual flow-through of the ITC will occur over the book life of the assets based on tax normalization rules that apply to PG&E. PG&E notes that for purposes of considering the value of the incremental capacity additions from the Helms Uprate presented in Chapter 3 of this Testimony, it calculated the net cost of the incremental capacity by calculating the forecasted revenue requirement of the Helms Uprate, including the required normalization of the anticipated ITC, and subtracting the hypothetical forecast of the revenue requirement for the Lifecycle Replacement Work, as further described in Chapter 3. Accordingly, the value calculation does take into account a more nuanced forecast of the ITC flow-through.

H. Project Timeline

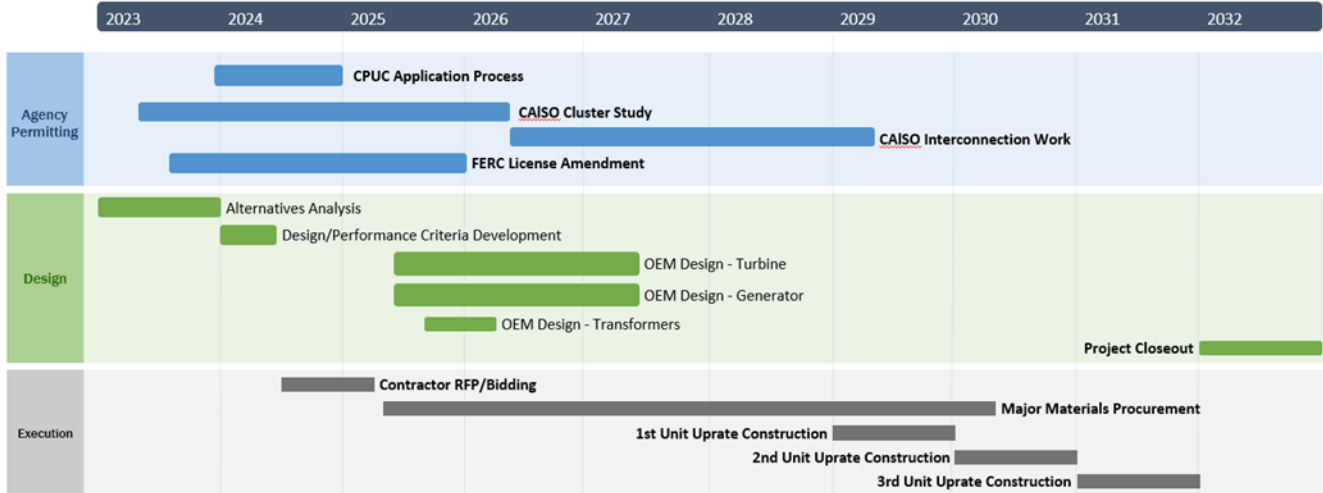
Conceptual project planning for the Helms Uprate has been underway since 2021. After the Helms generating equipment's OEM conducted high-level feasibility studies, PG&E determined in summer 2022 that an Uprate of the existing Helms facilities was feasible and should be pursued.¹³

Using the high-level scope developed during the feasibility studies, a CAISO application for interconnection was filed in Spring 2023 and FERC license amendment preparation began, with a planned submission of the third quarter of 2024.

The Preliminary design process is currently underway with drafting of equipment specifications beginning in early 2024, which will support the contracting with Uprate contractors and major equipment suppliers. The contracting process will be phased starting in early 2025 with execution of contracts for the long lead time materials in 2025, followed by execution of contracts for construction in 2026 through 2028, assuming CPUC approval of this cost recovery application prior to that time. Once these contracts are in place, the OEMs will perform detailed engineering in a cadence required to support the long lead materials procurement and construction, which is targeted for 2029-2031. Each unit's uprate and equipment replacement is expected to take approximately one year, with each unit's outage being performed consecutively. Below is an illustrative Gantt Chart showing estimated durations and sequencing of the major activities.

¹³ Attachment E, Black and Veatch Feasibility Study, describes other alternatives, including a Unit 4 option that may appear to be more cost-effective than the Uprate. The Study did not include costs for a necessary new gen-tie transmission line to support a Unit 4 and did not consider the cost of the Lifecycle Replacement Work that would need to occur if the Uprate is not implemented.

**FIGURE 2-1
PROJECT TIMELINE**



I. Safety

At PG&E, there is nothing more important than public, employee and contractor safety. In support of this commitment, PG&E has an established enterprise Contractor Safety Program. This program defines minimum requirements for managing and overseeing contractors and subcontractors that perform medium and high-risk work activities on behalf of PG&E, on either PG&E or customer sites and assets. This program helps to ensure that contractors performing work for PG&E maintain an acceptable level of safety certifications, ratings and best practices that exemplify their commitment to safe work practices.

Examples of the requirements of this program include maintaining a pre-qualified status in PG&E's third-party administrator, participation in PG&E's Gold Shovel program, adopting PG&E's best practices of conducting daily Job Hazards Analysis with crews prior to work, and the performance of regular job site safety observations.

One of the main requirements of the Contractor Safety Program is the Contractor's development of a Site-Specific Safety Plan (SSSP) for every project performed for PG&E. The development of this SSSP helps to ensure that the Contractor has thoroughly reviewed and planned the project prior to coming to site and identified the safety concerns and risks in the performance of the work. These plans identify safety risks and present mitigations to either eliminate,

1 avoid, or minimize safety hazards and are submitted to the PG&E Project Team
2 well prior to onsite work for review. These plans are then reviewed by both the
3 project team and internal safety professionals for understanding, thoroughness,
4 and confirmation that the contractor has performed their due diligence in
5 planning and preventing safety issues.

6 The Helms Uprate will be a complicated project with several contractors
7 performing work in concert with each other. All contractors will be required to,
8 not only develop SSSPs that discuss their scope of work, but also to coordinate
9 any concerns with the other contractors in the development of their SSSPs.
10 Elements to be discussed in these plans are expected to include Public Safety,
11 Confined Space, Congested Work Sites, Coordination of Work with Others, and
12 Heavy Load Handling.

13 **J. Conclusion**

14 The Helms Uprate project is a unique opportunity to increase the generation
15 and pumping capacity of the existing Helms Pumped Storage Plant for a
16 reasonable incremental cost while performing required lifecycle equipment
17 replacements. It is a unique opportunity because adding 150-180 MW by
18 leveraging the timing of planned lifecycle work, plus the expected availability of
19 tax credits, makes this project very cost competitive with other energy storage
20 options, as further discussed in Chapter 3. The Uprate Cost is estimated to be
21 \$462 million in nominal dollars, which includes 2.5 percent annual escalation
22 and 50 percent contingency. Compared with planned Lifecycle Replacement
23 Cost of \$300 million, and considering estimated ITCs of up to \$135 million, the
24 Net Incremental Capacity Cost for the Uprate is estimated to be approximately
25 \$27 million. The target construction timeline is from 2029 to 2031, with one unit
26 completed at the end of each year.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

HITACHI TURBINE STUDY

Summary of Turbine Uprate Study
(Phase-I, -II & -III Reports)

Table of Contents

- a. Summary of Phase-I Study (WP-3290, R0 on 2021-10-12)
- b. Summary of Phase-II Study (WP-3351, R0 on 2021-12-16)
 - b1.WP-3331, R0, Preliminary Plan for Enlarged Runner Outlet [Plan-A]
 - [REDACTED]
- c. Summary of Phase-III Study (WP-3444, R0 on 2022-10-16) [Plan-B]
- d. Conclusion

a. Summary of Phase-I Study

- a.1** Basic pump turbine ratings as well as civil conditions of water levels and head loss by the original Model Test in 1976 were summarized as a start of this study. See Table 1 below.

Table 1 Turbine Performance from model test results

Case	Net Head Ht (ft), (m)	Turbine Output Pt (khp), (MW)	Discharge Qt (cfs), (m ³ /s)	Guide Vane Opening GVOpr (%)
Max.	1744 ft (531.6m)	max. 555 khp (413.9MW)	3119 cfs (88.3m ³ /s)	90.7 %
Rated	1625 ft (495.3m)	max. 508 khp (378.8MW)	3073 cfs (87.0m ³ /s)	94.7 %
		rated 480 khp (357.9MW)	2888 cfs (81.8m ³ /s)	88.2 %
Min.	1430 ft (435.9m)	max. 450 khp (335.6MW)	3144 cfs (89.0m ³ /s)	109.9 %

- a.2** Record of Maximum (generator) output and maximum water level of Courtright Lake during the commissioning period in 1982-1984;
They were as follows which have been taken from (Hitachi) record.
-408MW on Unit 3 on 1984-04-24 in Test Run #13 as the final test in generation mode with head not recorded.

-8,168.99ft on 1984-05-24 upon 2 unit load rejection test (#1 & #2)
(specified max water level;8,184')

a.3 Expected maximum PT output of existing machine were presented as follows. (same as original model test report)

Case	Net Head(ft)	Output(MW)	Expected GVO(%)
Max Head	1,744' (531.6m)	413.9MW	90-91%
Rated Head	1,625' (495.3m)	378.8MW	94-95%
Min Head	1,430' (435.5m)	335.6MW	110%

b. Summary of Phase-II Study

b.1 Transient analysis at max output case under 3 different net heads in the original model test report as well as at the case with GM output of 427MW (corresponding to PT output of 436MW that had happened in June, 2020) have been done, which showed that it is safe to operate at PT output of 436MW.

b.2 Expected maximum output with new runner with a larger discharge diameter of [REDACTED] has been studied with increased PT output as shown below. [Plan-A]

Case	Net Head	PT Maximum Output	
		existing	Increased (discharge)
Hmax	1,744' (531.6m)	414 MW (88.3 m ³ /s)	455 MW (96.5 m ³ /s, 3,407 cfs)
Hnor	1,625' (495.3m)	379 MW (87.0 m ³ /s)	425 MW (97.8 m ³ /s, 3,454 cfs)
Hmin	1,430' (435.9m)	336 MW (89.0 m ³ /s)	340 MW (88.9 m ³ /s, 3,139 cfs)

c. Summary of Phase-III Study

- c.1 Evaluation of actual operating data given by PG&E on Feb 9, 2022 has been conducted, and records have been rearranged in Table 2 on page 3.
- c.2 One of the important findings are shown on Fig.5 “Expected curves between Model Test & Field Data” on page 9. Due to the specified method of the model test in IEC 193 at the time of Helms model test in 1976, efficiencies and wicket gate opening at higher out put area are different in model test report and field operation data. Please refer to the description on page 8 for details.
- c.3 Maximum PT output of existing PT at maximum servo stroke (19.94”) have been estimated as shown in Table 3-3 below considering cavitation and vibration caused by draft whirl, which is not recommended for continuous operation.

Table 3-3 Estimated Maximum Turbine Output at Maximum GVO

Net Head	Estimated Maximum Turbine Output	GVS	GVOp
Maximum 531.6 m	445 MW	Maximum 100% (19.94”)	Maximum 121%
Rated 495.3 m	420 MW		

- c.4 Expected maximum PT output by Plan-B is summarized in Table 3-4 & Fig 3.6 below in comparison with Plan-A.

Table 3-4 Summary of Runner Outlet Expansion Plans

Parameter, Item	Existing	Plan-A (Phase-II)	Plan-B (Phase-III)
Runner Outlet Diameter D ₂ (mm)	2486.9		
Diffuser Angle at DT Inlet 2 θ (°)			
Modified Area	---		
Turbine Partial Performance (Efficiency & Pressure Fluct.)	---	less than existing	equal to existing

Pump Performance at High Pump Head	---	less than existing	less than existing
---------------------------------------	-----	-----------------------	-----------------------

Hmax	1,744' (531.6m)	414 MW (88.3 m ³ /s, 3118 cfs)	455 MW (96.5 m ³ /s 3408 cfs)	463 MW (98.0 m ³ /s 3461 cfs)
Hnor	1,625' (495.3m)	379 MW (87.0 m ³ /s, 3072 cfs)	425 MW (97.8 m ³ /s 3454 cfs)	433 MW (99.4 m ³ /s 3510 cfs)
Hmin	1,430' (435.9m)	336 MW (89.0 m ³ /s 3143 cfs)	340 MW (88.9 m ³ /s 3139 cfs)	345 MW (90.2 m ³ /s 3185 cfs)

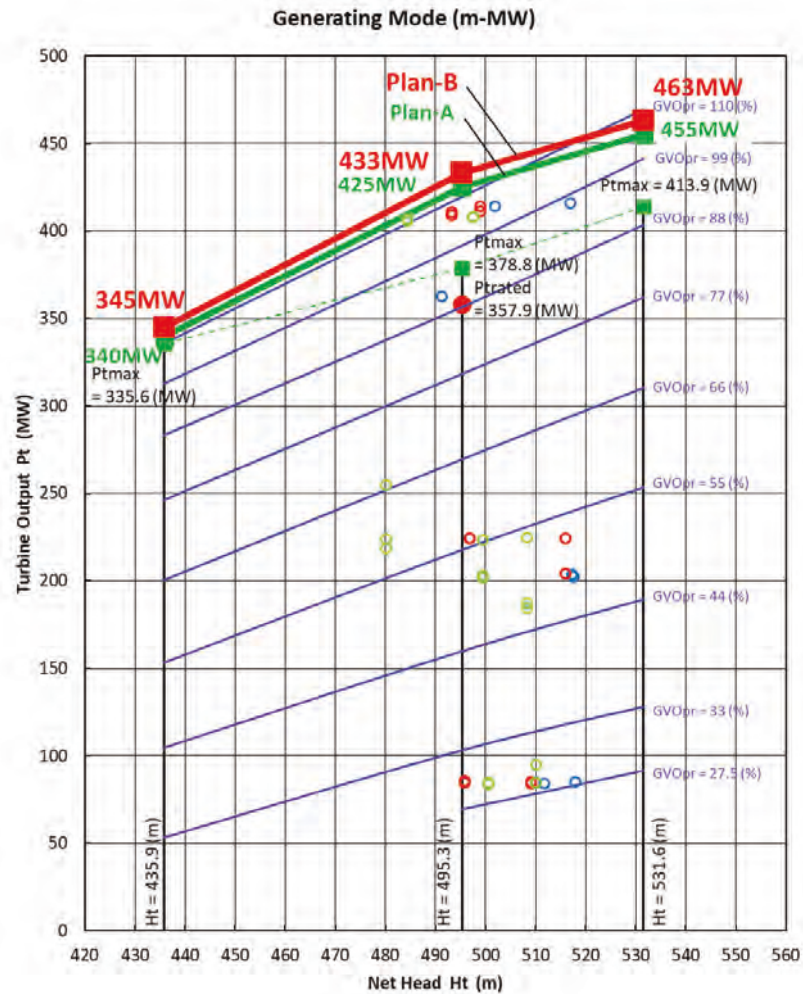


Fig 3-6 Expected Maximum PT Output by Plan-A & Plan-B

c.5 Please refer to another chart (Fig 3-6a) below, in which higher output area has been enlarged for a closer understanding.

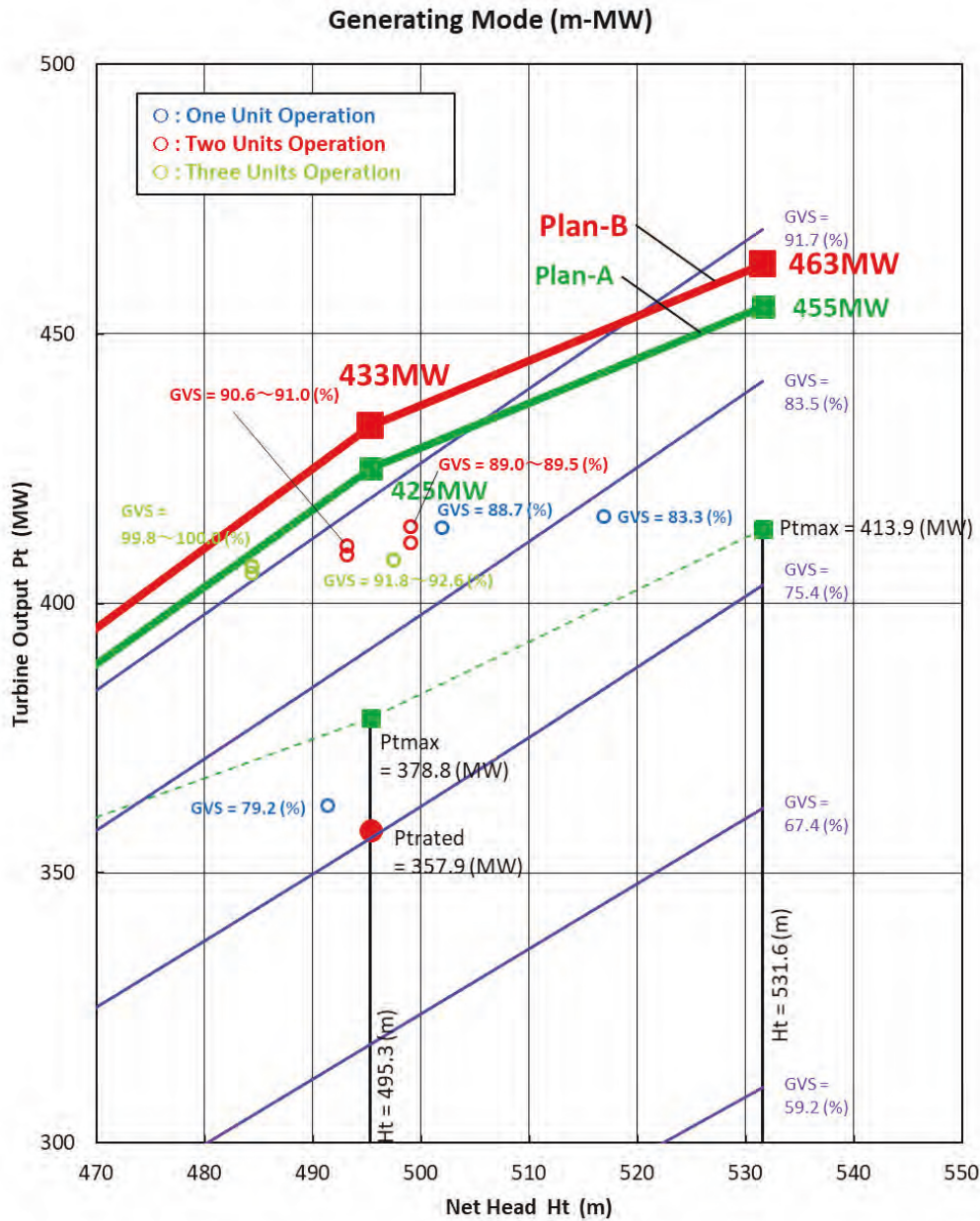


Fig 3-6a Expected Maximum PT Output by Plan-A & Plan-B (top area only)

One point to be noted here is that the gate servo stroke at 463MW (Plan-B) is not 19.94", but around 90% (18") to avoid cavitation & vibration as explained

in Phase-III report. The servo stroke at 455MW (Plan-A) is around 88% (17.5") by the same reason.

d. **Conclusion;**

It is concluded that Plan-B PT is expected to produce 463MW (PT output, but not GM output) at the maximum net head of 1,744', and 433MW at rated net head of 1,625'. They are roughly converted to **454MW and 424MW** as generator output respectively by using 0.98 as the generator efficiency.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

HITACHI PUMP STUDY

Deliverable of Phase-IV, Pump Study

Section 1, Pump Performance of Existing Unit

Original model test had been witnessed in November, 1975 at Hitachi Works in Japan, and the Model Test Report W1QLH-003 had been submitted in 1976 for PG&E's review and record. Cover of the report is attached as Fig. 1-1 and the Pump performance curves of the original model is attached as Fig. 1-2 below. Since the conversion formulae from the model to prototype in pump mode in 1976 are different from the current IEC, this study to predict pump performance of Plan-A and Plan-B is being conducted per the current IEC based upon the model pump performance data shown in Fig. 1-2 above.

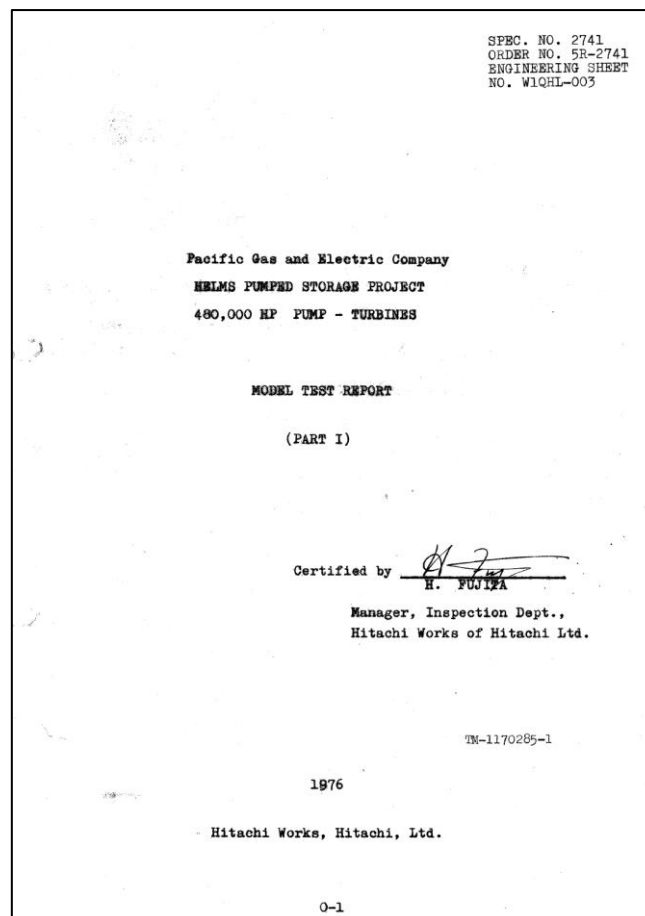


Fig. 1-1 Cover of Model Test Report in 1976

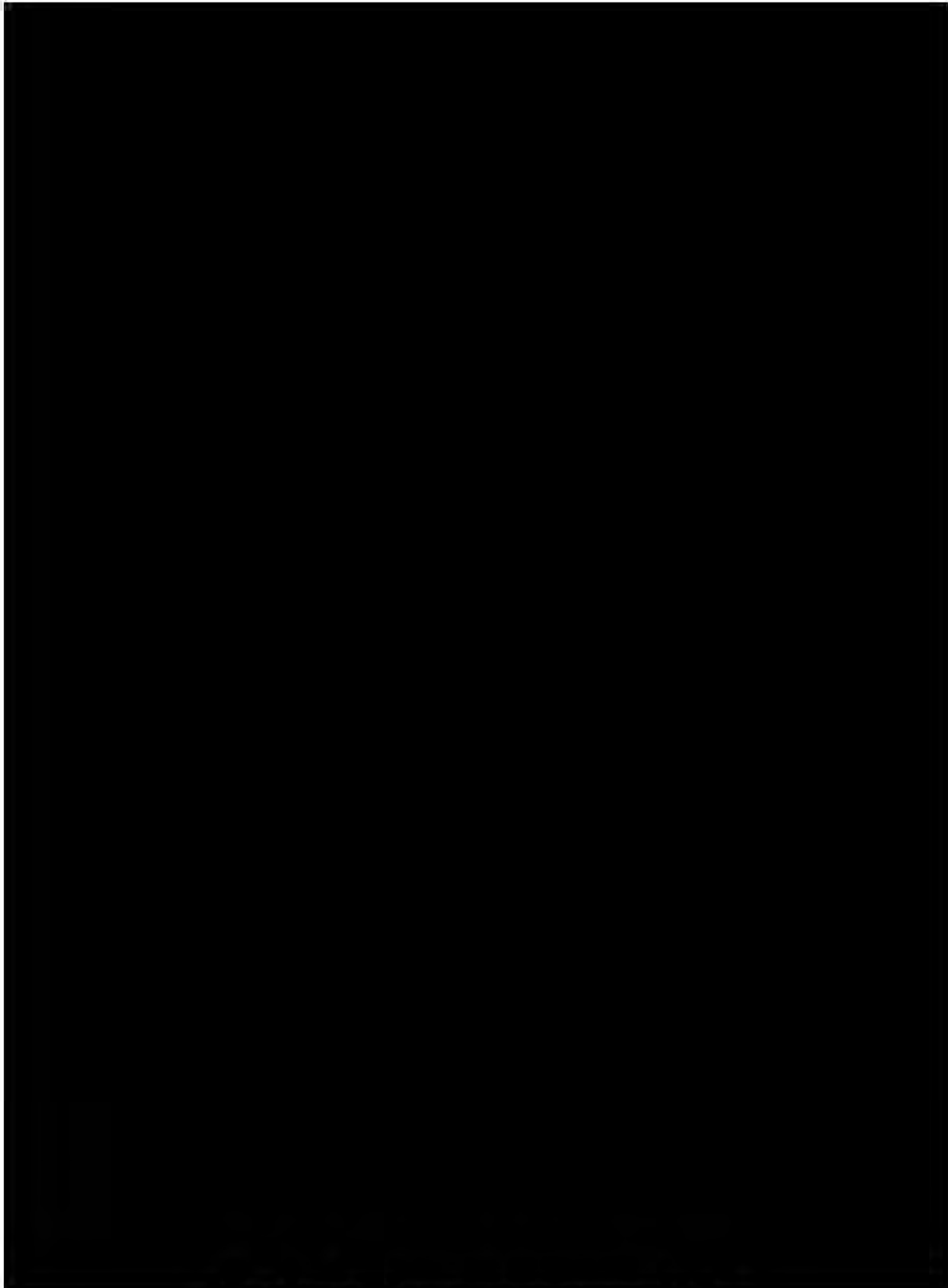


Fig. 1-2 Model Pump Performance in 1976

Section 1-1, Step-up of Pump Efficiencies (for 2 different purposes)

In order to get prototype pump efficiency from the model, the “**Moody’s 1/5 Power Method**” had been adopted in 1976, but a coefficient in the formulae is different to get prototype pump efficiencies and to get prototype discharge & total dynamic head as explained below.

For prototype pump efficiencies;

$$\begin{aligned}\eta_{pr} &= \eta_m + 0.8 (100 - \eta_{m \max.}) \left\{ 1 - \left(\frac{D_m}{D_{pr}} \right)^{\frac{1}{5}} \right\} \\ &= \eta_m + 0.8 (100 - \blacksquare) \left\{ 1 - \left(\frac{\blacksquare}{5130.3} \right)^{\frac{1}{5}} \right\} \\ &= \eta_m + \blacksquare\end{aligned}$$

η : Efficiency

D : Reference diameter

Subscript

pr : Prototype

m : Model

max. : Maximum

The step-up to get prototype pump efficiency is **3.39%** as above.

For prototype pump discharge & total dynamic head;

When we calculate prototype discharge and total dynamic head from model data, the coefficient of 0.8 in the above “**Moody’s 1/5 Power Method**” is defined as 0.5 as shown below.

$$\begin{aligned}\eta_{pr} &= \eta_m + 0.5 (100 - \eta_{m \max.}) \left\{ 1 - \left(\frac{D_m}{D_{pr}} \right)^{\frac{1}{5}} \right\} \\ &= \eta_m + 0.5 (100 - \blacksquare) \left\{ 1 - \left(\frac{\blacksquare}{5130.5} \right)^{\frac{1}{5}} \right\} \\ &= \eta_m + \blacksquare\end{aligned}$$

The step-up efficiencies to get prototype pump discharge and total dynamic head is [REDACTED] which is different from above [REDACTED] to get pump efficiencies.

Section 1-2, Step-up of Pump Discharge & Total Dynamic Head

When we calculate the prototype discharge & total dynamic head from the model data, square root of the ratio of prototype efficiency [REDACTED] + 2.12% in above 1-1) & model efficiency ([REDACTED]%) is to be adopted in the model test in 1976, while this conversion factor is not used in the current IEC standard.

Therefore, the prototype pump discharge & total dynamic head derived from the same model should be different by the factor of $\sqrt{\eta'_{pr \max} / \eta_{m \max}} = \sqrt{[REDACTED]} = [REDACTED]$. Detailed calculation steps for conversion in 1976 and by the current IEC are shown below,

1-2a) Model Test Report in 1976

-Pump Discharge

$$Q_{pr} = Q_{m1000} \times \left(\frac{N_{pr}}{1000} \right) \left(\frac{D_{pr}}{D_m} \right)^3 \sqrt{\frac{\eta'_{pr \max.}}{\eta_{m \max.}}}$$

-Pump Total Dynamic Head

$$H_{pr} = H_{m1000} \times \left(\frac{N_{pr}}{1000} \right)^2 \left(\frac{D_{pr}}{D_m} \right)^2 \sqrt{\frac{\eta'_{pr \max.}}{\eta_{m \max.}}}$$

Q : Pump discharge
 H : Pump total dynamic head
 N : Rotational speed

Subscript

1000 : Rotational speed of model test for normalizing data of pump mode test

$$\sqrt{\frac{\eta'_{pr \max.}}{\eta_{m \max.}}} = \sqrt{\frac{[REDACTED]}{[REDACTED]}} = [REDACTED]$$

1-2b) IEC 60193

-Pump Discharge

$$Q_{pr} = Q_{m1000} \times \left(\frac{N_{pr}}{1000} \right) \left(\frac{D_{pr}}{D_m} \right)^3$$

-Pump Total Dynamic Head

$$H_{pr} = H_{m1000} \times \left(\frac{N_{pr}}{1000} \right)^2 \left(\frac{D_{pr}}{D_m} \right)^2$$

Section 1-3, Prototype Pump Input

In 1976 model test report, the prototype pump efficiencies had been calculated by the first formula in Section 1-1 above as $\eta_{pr} = \eta_m + \text{[redacted]}(\%)$, while the pump input had been calculated by the formula below with the use of $\eta'_{pr} = \eta_m + \text{[redacted]}(\%)$.

Prototype Pump Input

$$P_{pr} = \rho_{pr} \times g_{pr} \times Q_{pr} \times H_{pr} / \eta'_{pr}$$

Therefore, the prototype pump efficiencies and the pump input in 1976 model test report are not consistent.

Section 1-4, Pump Performance of Existing Prototype

Pump performance of existing prototype calculated by the formulae in 1976 model test report and that by the current IEC standard are shown in **Fig.2** below in different colors. (**black line**; 1976 report & **blue line**; current IEC)

Horizontal axis shows “Total Dynamic Head” for all curves. Curves per 1976 model test report have been derived by multiplying the square root of the ratio of prototype & model maximum efficiencies ($\sqrt{\eta'_{pr \max} / \eta_{m \max}} = \sqrt{\text{[redacted]}} = \text{[redacted]}$), while curves per the current IEC are all shifted slightly down from those per 1976 model test report as shown.

As for the pump efficiencies, the step-up value per the current IEC becomes **[redacted]%** which is lower by **[redacted]%** than 1976 model test report, and efficiencies at higher total dynamic head becomes much lower since calculated total dynamic head is smaller by the factor of **[redacted]**.

Considering several inconsistency in 1976 Model Test Report, we would like to propose to use **blue line in Fig 2** below as a base to estimate expected pump performance of Plan-A & Plan-B, which are the original model pump data converted to the prototype by using the current IEC standard.

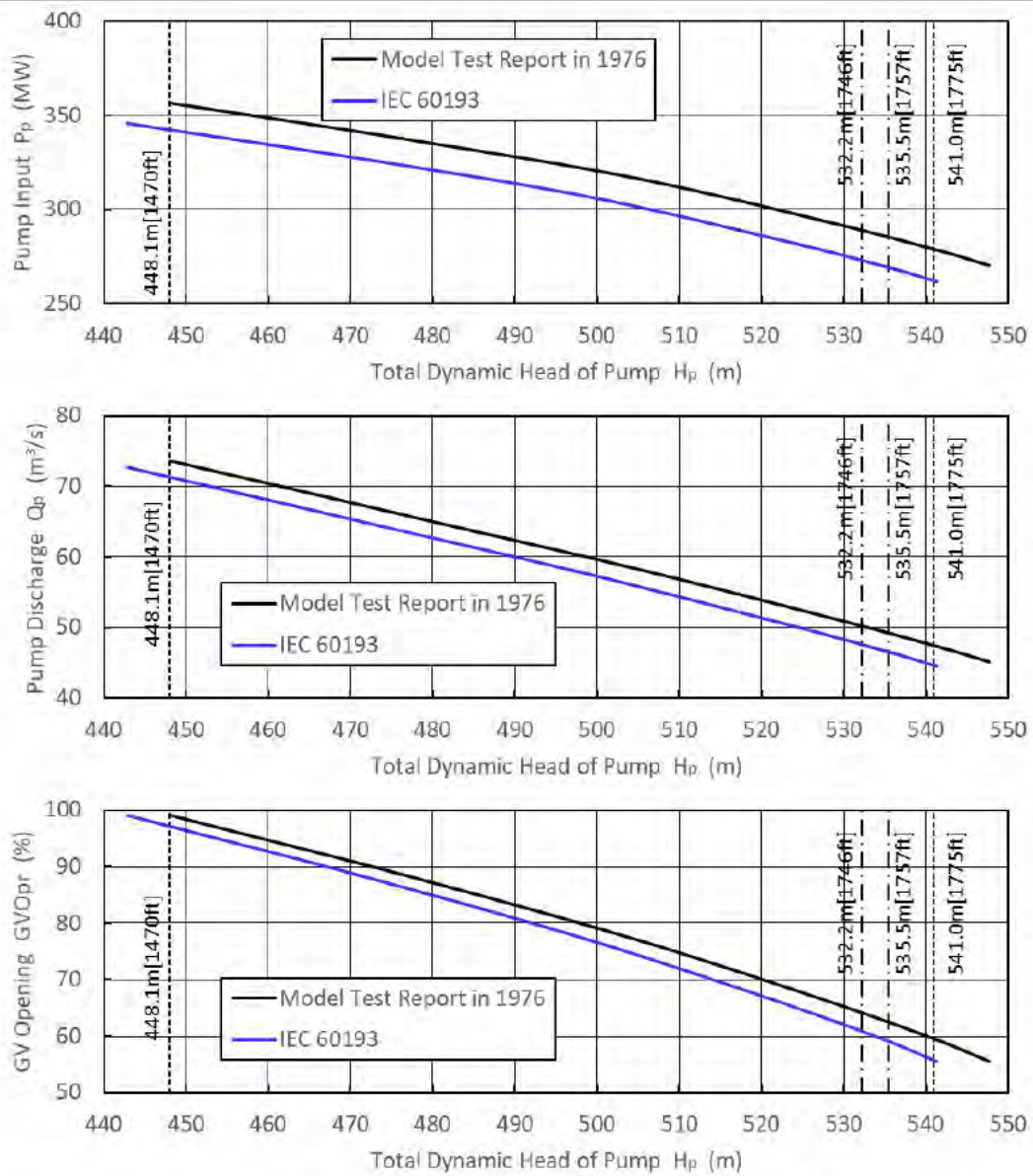
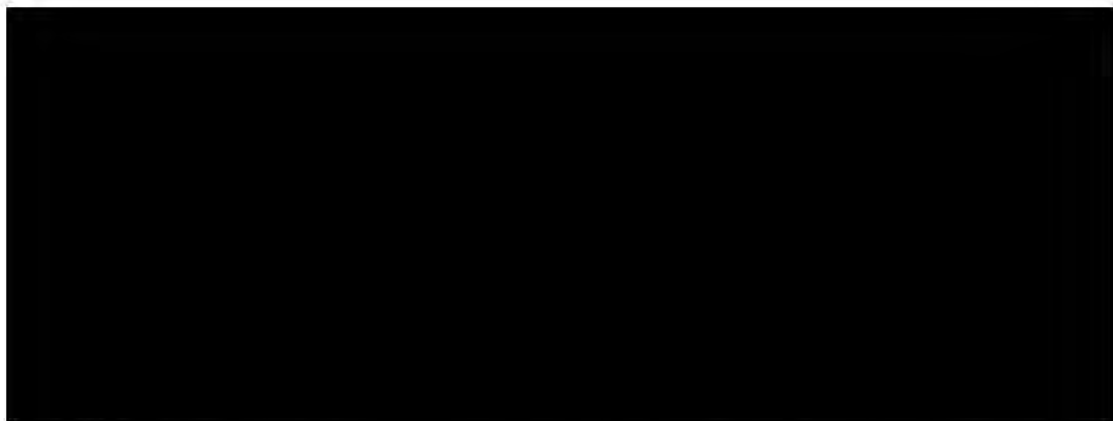


**Fig.2 Prototype Pump Performance of Existing Pump-Turbine
Calculated from Model Test Data in 1976**

Section 2, Expected Pump Performance of Plan-A & Plan-B

Section 2-1, Pump Performance of Existing Prototype

Pump performance on pages 3-1 through 3-3 in 1976 Model Test Report have been picked up and shown in Table 1 on page 10 afterword. Numbers in m-kW unit are also shown for our easier calculation & reference.

First of all, we would like to clarify realistic parameters related to expected pump performance as a base as follows.

- a. Total dynamic pump head of 1,775' seems to be too high;

Maximum total dynamic head of 1,775' seems to have been calculated by using 3 times of the maximum pump discharge @ minimum total dynamic head of 1,470', which is 2,599 cfs x 3 = 7,797 cfs as follows.

$$H_L = 0.5 \left(\frac{2599 \times 3}{1000} \right)^2 = 30.4 \cong 31 \quad (\text{ft})$$

$$1,744' + 31' = 1,775'$$

However, this condition will not happen since the pump discharge at the maximum total dynamic head of 1,775' should be 1,675 cfs, which is much smaller than 2,599 cfs used in above formula.

For realistic conditions of maximum total dynamic head, head loss calculated by using the correct pump discharge of 1,675 cfs is as follows for 3 unit pump operation and one unit operation.

$$H_L = 0.5 \left(\frac{1675 \times 3}{1000} \right)^2 = 12.6 \cong 13 \quad (\text{ft}) \quad (3 \text{ unit pump})$$

$$H_L = 0.5 \left(\frac{1675}{1000} \right)^2 = 1.4 \cong 2 \quad (\text{ft}) \quad (1 \text{ unit pump})$$

Considering the fact that the pump discharge gradually increases as the dynamic head decreases, more realistic calculations follow.

$$H_L = 0.5 \left(\frac{1733 \times 3}{1000} \right)^2 = 13.5 \cong 14 \quad (\text{ft}) \quad (3 \text{ unit pump})$$

$$H_L = 0.5 \left(\frac{1772}{1000} \right)^2 = 1.6 \cong 2 \quad (\text{ft}) \quad (1 \text{ unit pump})$$

Through the above calculation, realistic pump operating conditions are as below by using correct pump discharge in the original table for 1 unit & 3 units pump operation.

	Static Head (ft)	Total Dynamic Head (ft)	Discharge (cfs)
1 Unit Operation	1744	1746	1772
3 Units Operation	1744	1758	1733

1 ft = 0.3048m

	Static Head (m)	Total Dynamic Head (m)	Discharge (m ³ /s)
1 Unit Operation	531.6	532.2	50.2
3 Units Operation	531.6	535.8	49.1

As explained in Section 1-4 above, we would like to use the **blue line in Fig 2** on page 6 as the base pump performance. In addition, the total dynamic heads for which expected pump performance of Plan-A & Plan-B will be those 1976 model test report plus 1,746' & 1,758' above, which are more realistic explained above. (1,470', 1,500', 1,600', 1,700', 1,746', 1,758' & 1,775').

Section 2-2, Expected Pump Performance of Plan-A

In Plan-A, the runner outlet diameter has been enlarged by [REDACTED] from 97.91" (2,486.9mm) to [REDACTED] but the runner inlet diameter of 201.98" (5,130.3mm) and the runner inlet height of 13.03" (330.9mm) have not been changed. By this modification of the runner, the pump performance in low discharge & higher dynamic head area will adversely be affected due to the local reverse flow at the pump inlet area, which is the enlarged runner outlet area. However, the pump performance away from the low discharge area will not be affected from the original model.

Please refer to Fig. R1 as a general pump performance curve on page 13. A reverse flow will happen at & below 82% pump discharge area. This reverse flow is much noticeable in low discharge area. Therefore, pump operating range is generally be set at the right bottom area of the E vs. Q curve.

Through our evaluation of Plan-A modification, expected pump performance is shown in the middle of Table 2 (page 11) and in **blue curves** in Fig 3 (page 12).

Even if the pump performance at maximum total dynamic head (1,775') area is expected to become low, 3 units pump operation at 1,775' head will not happen as explained in 2-1 above. In addition, maximum operable pump head by Plan-A seems to be at 1,746' pump (532.2m) head as shown in Table 2 & Fig.3.

Section 2-3, Expected Pump Performance of Plan-B

In Plan-B, the runner outlet diameter has been enlarged by [REDACTED] from 97.91" (2,486.9mm) to [REDACTED] but the runner inlet diameter of 201.98" (5,130.3mm) and the runner inlet height of 13.03" (330.9mm) have not been changed. Since the increase in the runner outlet diameter from Plan-A is [REDACTED] which is [REDACTED], the adverse effect in pump performance is minimal.

In addition, even if the modification of the draft tube is quite different in Plan-A & Plan-B, not much difference is expected in pump performance since the modification of the draft tube is both "velocity increase flow" for Plan-A & Plan-B. Expected pump performance for Plan-B is shown in the bottom of Table 2 (page 11) and in **red curves** in Fig 3 (page 12). The maximum operable pump head for Plan-B should be the same as that of Plan-A, which is 1,746' (532.2m).

Table 1 Pump Parameters of Existing Pump-Turbine

1. Original performance in the contract at construction

0) Head Variations

	max.		nor.		min.
Static Head	1,744'		1,665'		1,470'
Effective Head of Turbine	1,744'		design 1,625'		1,430'
Total Dynamic Head of Pump	1,775'	1,700'	(1,600')	design 1,500'	1,470'

1' = 0.3048m

	max.		nor.		min.
Static Head	531.6m		507.5m		448.1m
Effective Head of Turbine	531.6m		design 495.3m		435.9m
Total Dynamic Head of Pump	541.0m	518.2m	(487.7m)	design 457.2m	448.1m

1) Pump performance

(* Guarantee Value)

Total Dynamic Head (ft)	Discharge (cfs)	Input (hp)	Guaranteed Efficiency (%)
1,470	2,599	478,100	
1,500	2,511 (2,400 *)	—	
1,600	2,226	—	
1,700	1,920	—	
1,775	1,675	—	

1 hp = 0.7457kW

Total Dynamic Head (m)	Discharge (m ³ /s)	Input (kW)	
448.1	73.6	356,500	
457.2	71.1 (68.0)	—	
487.7	63.0	—	
518.2	54.4	—	
541.0	47.4	—	

Table 2 Expected Pump Performances

2. Expected Pump Performances

1) Existing from calculation of IEC

Total Dymanic Head (m)	Discharge (m ³ /s)	Input (kW)	Efficiency (%)
448.1	71.2	342,100	████
457.2	68.8	336,500	████
487.7	60.7	316,000	████
518.2	52.0	288,600	████
532.2	47.6	272,800	████
535.8	46.5	268,900	████
541.0	44.7	262,200	████

2) Plan-A

Total Dymanic Head (m)	Discharge (m ³ /s)	Input (kW)	Efficiency (%)
448.1	71.2	342,100	████
457.2	68.8	336,500	████
487.7	60.0	313,400	████
518.2	51.0	285,200	████
532.2	46.1	267,200	████
535.8	44.6	261,400	████
541.0	42.0	250,800	████

3) Plan-B

Total Dymanic Head (m)	Discharge (m ³ /s)	Input (kW)	Efficiency (%)
448.1	71.2	342,100	████
457.2	68.8	336,500	████
487.7	59.8	312,400	████
518.2	50.7	283,900	████
532.2	45.8	266,000	████
535.8	44.3	260,200	████
541.0	41.7	249,500	████

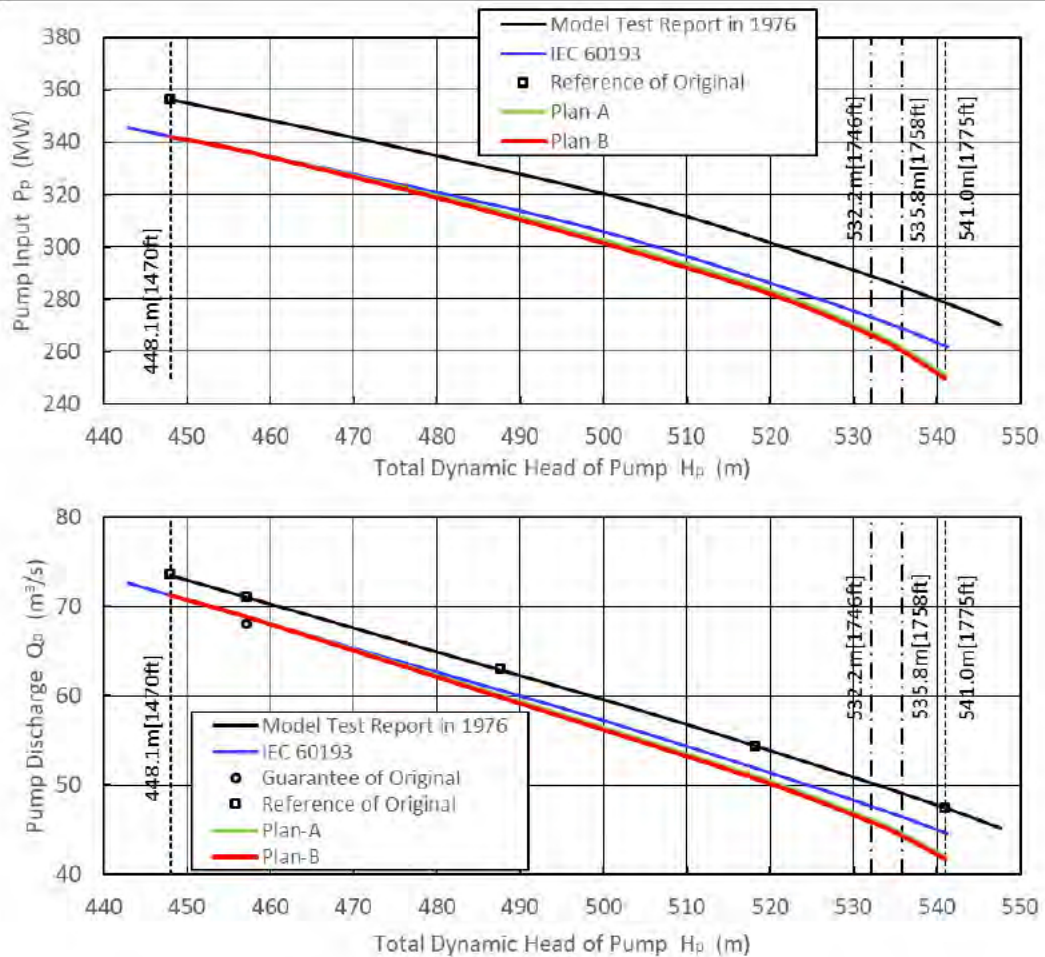


Fig. 3 Expected Pump Performances of Plan-A and Plan-B

--- For Reference ---

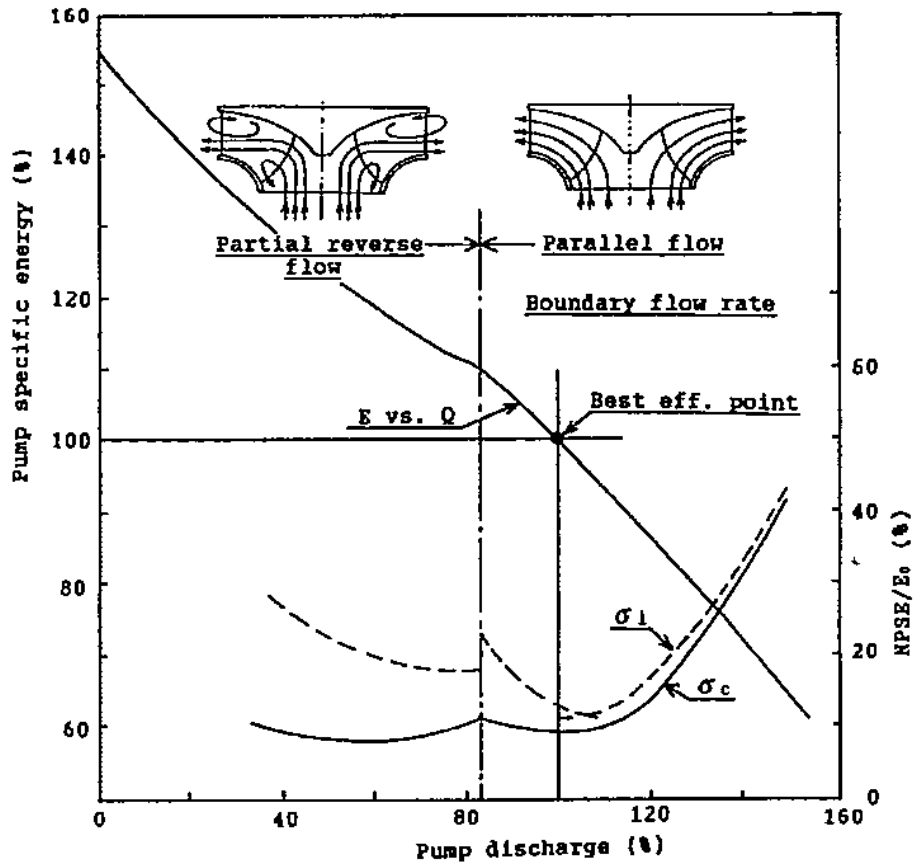


Fig. R1 Typical Diagram of Pump Performance

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT C

VOITH GENERATOR STUDY

GENERATOR Uprate study executive summary	HELMS U1-3	
Technical Report	Doc ID:	2-10276992
	Doc. Rev.:	-

HELMS PUMP STORAGE Unit No. 1-3

GENERATOR Uprate study executive summary Technical Report

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DISCLAIMER

This report was prepared to the best of Voith Hydro, Inc.'s (Voith) knowledge, belief, and technology.

The facts contained in this report are true and correct. The reported analysis, recommendation, and conclusions of stress and fatigue assessment are limited by the reported drawings, operation conditions, and assumptions as detailed within the report.

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1 Introduction

The Helms generators (U1-3) were originally nameplated at 390 MVA @0.9 pf by Westinghouse and placed in commercial operation in 1984. The generators are air cooled with special water-cooled stator windings. Units 1 and 3 were rewound in 2002 by Voith at the same rating of 390 MVA @0.9 pf. The rotors were replaced in 2015 by Alstom. U2 was rewound by Voith in 2020 at the rating of 450 MVA @0.9 pf.

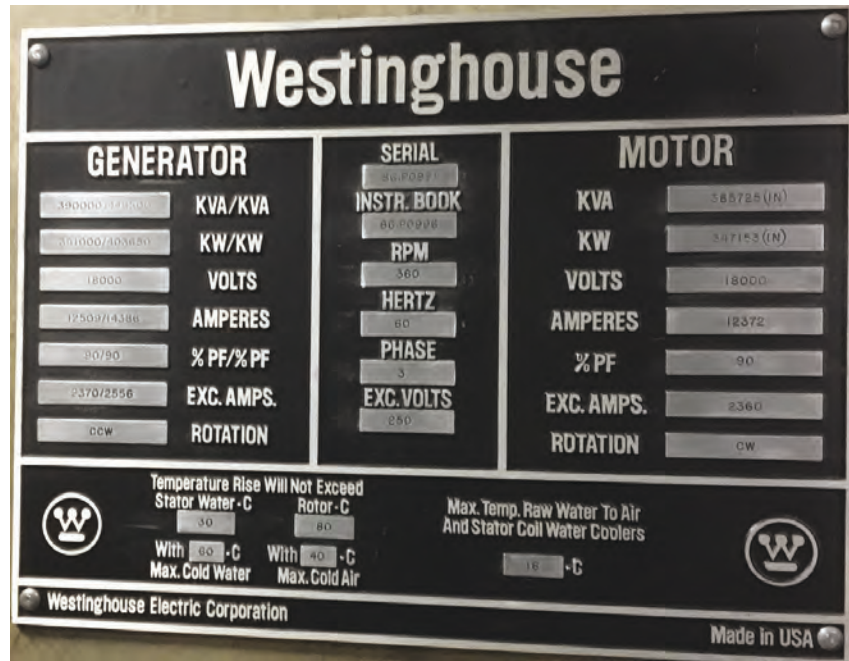


Figure 1 – Original Rating Plate

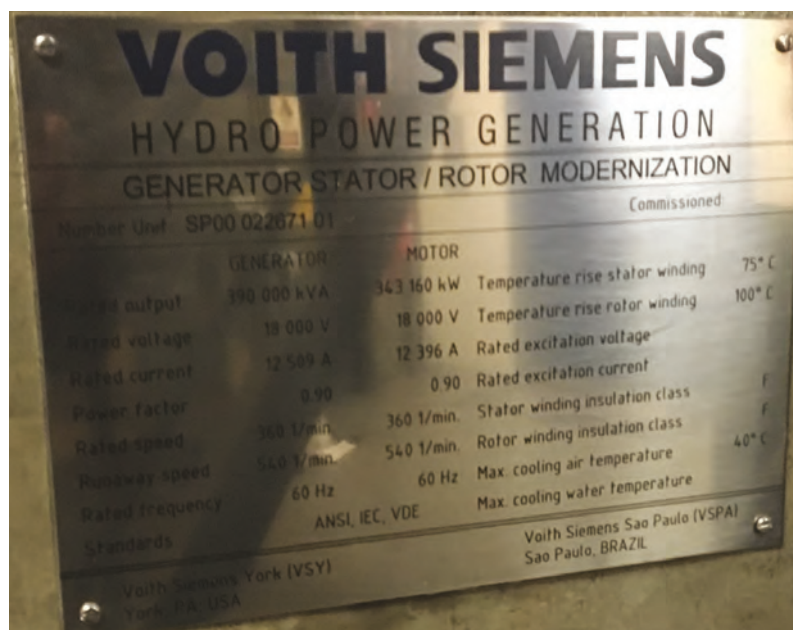


Figure 2 - U1 & U3 Rewound Rating Plate

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Figure 3 - Rotor Supply Rating Plate

		VOITH	
Synchronous Generator - Stator Winding			
	Generator	Motor	
Rated output:	450000	385725	kVA
Rated output:	405000	347152	kW
Rated voltage:	18000	18000	V
Rated current:	14434	12372	A
Rated factor:	0.9	0.9	
Frequency:	60	60	Hz
Rated speed:	360	360	rpm
Runaway speed:	504		rpm
Rated excitation voltage:			V
Rated excitation current:			A
Rotation (NDE View):	CCW	CW	
Type:	1DH-7258-3WS10-Z		Water cooled winding
Serial number:	2008656 01		Country of design/manufacture: Brazil
			Year of manufacture: 2020
		Thermal class	
		Stator winding: F	
		Temperature rise	
		Stator winding: 60 °C	
		Above cold air temp. of: 40 °C	
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Figure 4 - U2 Rewound Rating Plate

Voith used available drawings, operational data, and in-house calculation tools to investigate the following:

1. What is the maximum potential power output capable from U2 keeping the current stator winding, stator core, rotor, and winding cooling system?
2. What is the maximum potential power output capable from U1 & U3 keeping the current stator winding, stator core, rotor, and winding cooling system? The winding installed in U1&U3 consists of less copper than the U2 winding.

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During this study Voith was informed by PGE that the maximum possible turbine capacity of 515 MW per unit was achievable with a total plant flow of 4,150cfs @ a tail water elevation of 6,429 Ft. It should be noted that 515 MW at the turbine with a 0.90 pf results in a generator rating of 572 MVA.

Voith used this information to determine if the generators could potentially meet or exceed this turbine rating. Voith also investigated the current stator core and clamping system, foundation loading, thrust bearing capacity and the shaft and shaft coupling stresses at the maximum uprate power.

The mechanical scope considered a few options:

1. Keeping the current stator core and winding currently installed in U2.
2. Replacing the stator core and winding in the unit U2.
3. Keeping the current stator core and winding currently installed in U1 & U3.

This report will discuss the findings on a high level. Details have already been provided to PG&E in the form of PowerPoint presentations and should be referenced for details.

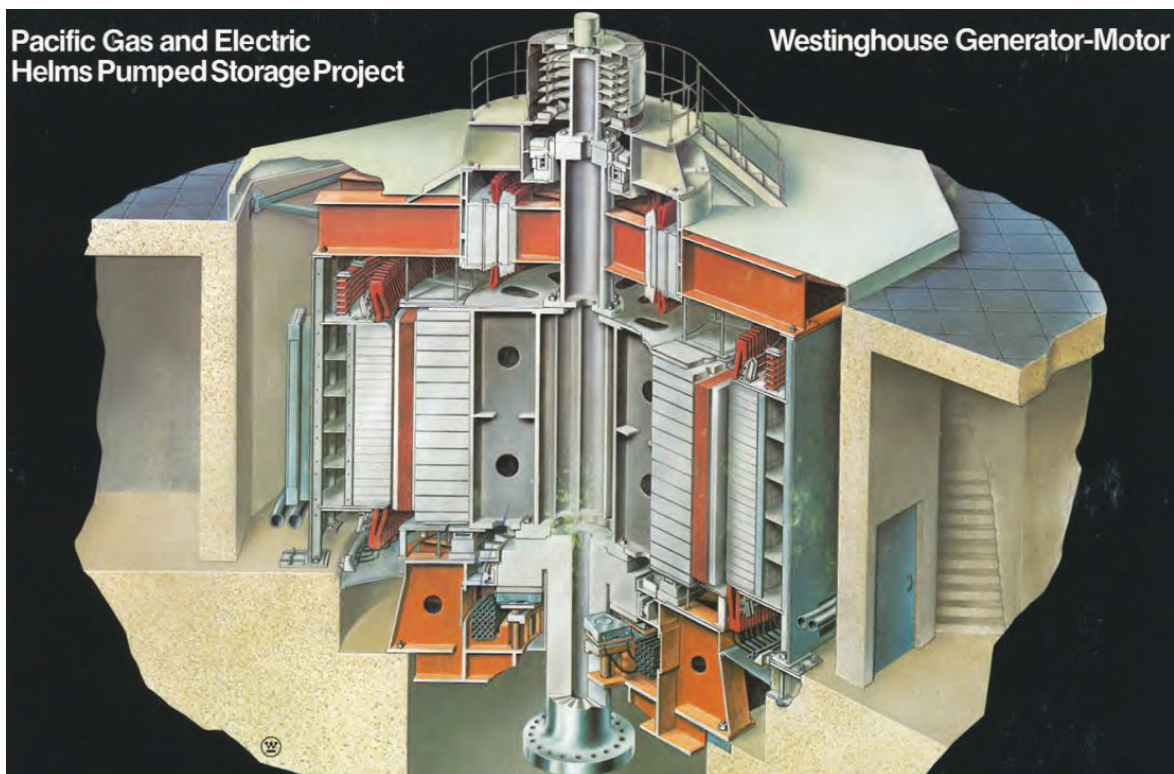


Figure 5 - Original Helms Cross Section

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2 Reference Detailed Reports

The following detailed presentations were created to review the input data, findings and recommendations and should be consulted for in-depth analysis for each topic:

- Electromagnetic calculation:
- Thrust Bearing Investigation:
- Stator frame, core and foundation:
- Stator brakes:
- Shaft line analysis:
- Shaft and shaft coupling stresses:

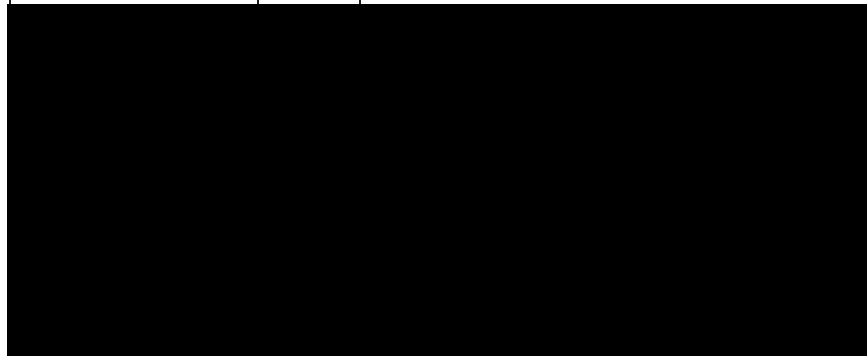


3 Generator Information

The original equipment manufacturer was Westinghouse.

A comparison of the name plate information and winding details are shown in the table below

		Unit 1 & 3	Unit 2
Rating	MVA	390	450
Power Factor		0.90	
Voltage	kV	18	
Phases		3	
Frequency	Hz	60	
No. of poles		20	
No. of slots		240	
Speed	rpm	360	
Runaway speed	rpm	540	



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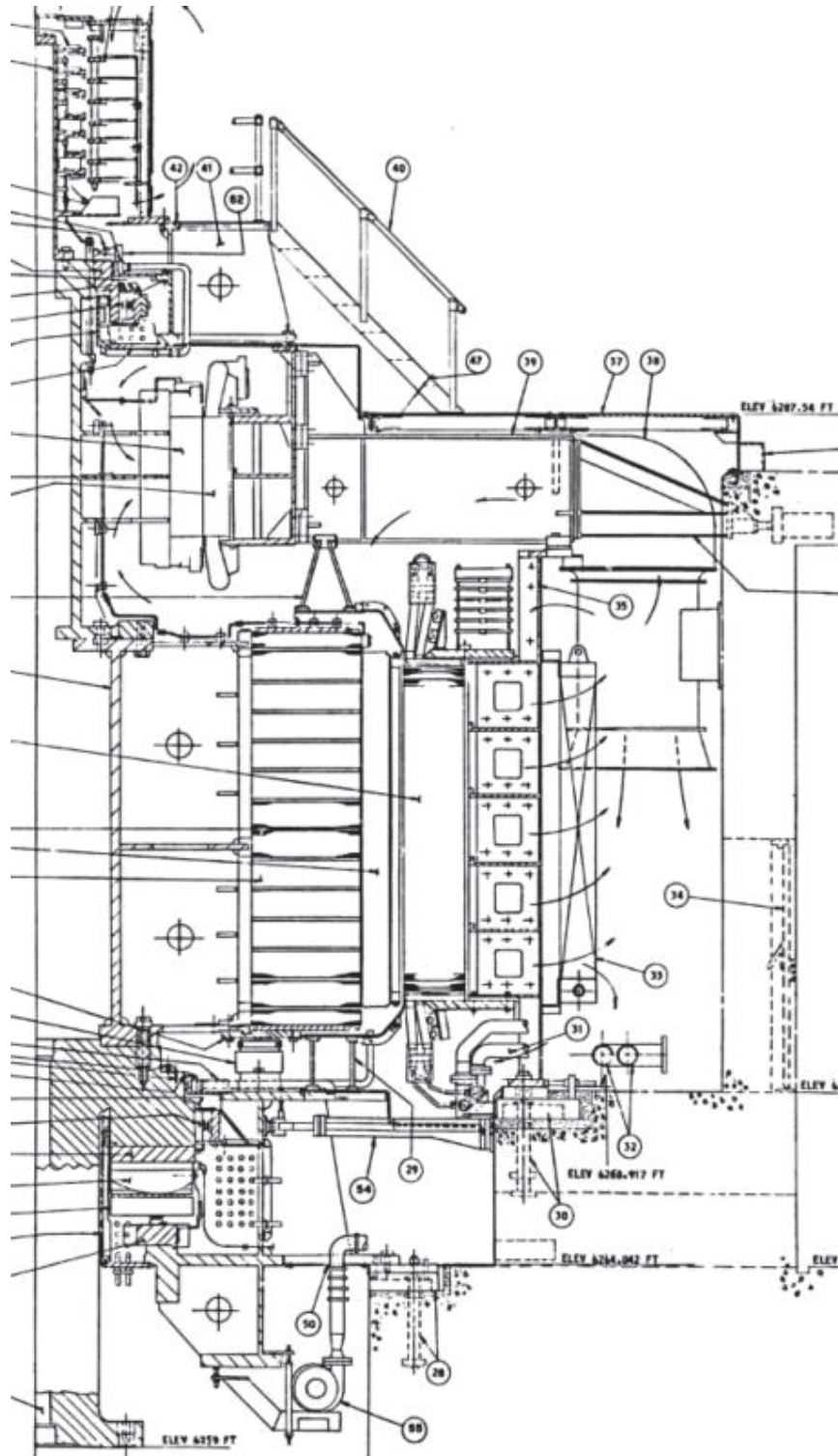


Figure 6 - Generator Cross Section

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4 Summary of the Analysis

4.1 Electromagnetic Calculation

The electromagnetic calculation of the existing OEM machine as well as the uprated machine was performed in our Voith Hydro Engineering Competence Center located in Brazil. Our expert team has extensive knowledge and many years of experience performing generator calculations. Voith uses proprietary in-house developed software tools to accurately simulate existing machines. Using available operational test data, a calibration of the simulation ensures realistic results for key parameters of the machine such as power, losses, and temperatures.

Unit 2 stator winding (installed in 2020), re-use existing core:

Voith first looked at the water-cooling capacity in the stator winding. The total flow is [REDACTED] which results in a water velocity of [REDACTED] which is nearing the limit of [REDACTED] based on the duct area inside the hollow conductors. This limit is based on Voith's experience. Due to this limitation the water temperature will rise for an uprate to 572 MVA. Calculations indicate the rise will be 35 K, resulting in an absolute hot water temperature of 75.3°C (40°C cold water). Restricting the hot water temperature to 70°C, the machine can reach a maximum uprate of 520 MVA.

The existing circuit rings are acceptable to handle the uprated power of 572 MVA but a very close investigation needs to be performed to study magnetic distances. The current arrangement is tight and there were some issues that occurred during the recent commissioning that had to be addressed.

The existing stator core can handle the increased rating however, during the 2020 rewind extensive damage was found in the existing core which required major repairs to move forward with the rewind. As the power is increasing so is the temperature and vibrations in the stator core. PG&E should understand that the core is likely nearing the end of its useful life and should consider replacing it. Voith believes there is considerable risk operating the existing core at higher output based on the condition of the core as it was left during the 2020 rewind.

Although the analysis did not include the new rotors installed at Helms, Voith did review rotor data provided by PG&E and noted that the rotors have a class B temperature rise (80K) with a field current of 2726 A and a class F temperature rise (100K) with a field current of 3050 A (reference the rating plate shown earlier). At a rating of 572 MVA, Voith calculated a field current of 3060 A, which would mean the temperature rise of 100K will be slightly exceeded. If PG&E would like to operate the rotor at a class B rating the machine will be limited to 493 MVA @ a field current of 2723 A.

It should be noted that the U2 winding differs considerably with that installed in U1&3 with how the connections are made in the circuits. This difference results in much lower electrical vibrations.

Unit 2 with a new stator core and re-designed winding and hydraulic circuit:

Voith looked at an option where the stator core would be replaced as well as a new stator winding with a different hydraulic circuit. Going in this direction it was determined that the machine could reach the 572 MVA rating while maintaining the water temperature rise below 30 K. The restriction of the existing rotor is still in-place. The existing pure water system must be looked at in more detail to be sure it can provide adequate flow required for the new winding hydraulic circuit. The new winding would be like that currently installed in U2 to reduce the electrical vibration dramatically compared to the windings installed in U1 & U3. The circuit rings and magnetic distances have to be closely looked at. [REDACTED]

[REDACTED] The water box design should also be further studied to understand the vibration levels to ensure mechanically it can handle the higher vibration from a stress and fatigue standpoint.

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Units 1 & 3 stator winding (installed in 2002), re-use existing core:

Voith first looked at the water-cooling capacity in the stator winding. The total flow is [REDACTED] which results in a water velocity of [REDACTED] which is nearing the limit of [REDACTED] based on the duct area inside the hollow conductors. This limit is based on Voith's experience. Due to this limitation the water temperature will rise for an uprate to 572 MVA. Calculations indicate the rise will be 40 K, resulting in an absolute hot water temperature of 80.3°C (40°C cold water). Restricting the hot water temperature to 70°C, the machine can electrically and thermally reach a maximum uprate of 481 MVA, however Voith would not recommend a continuous rating above the current 390 MVA for several reasons. First, the existing stator cores are likely in a similar condition found in unit 2 during the 2020 rewind. Operating the unit at a higher rating will increase the temperatures and vibration levels. This will lead to further degradation of the interlamination insulation between the thin stator laminations. Eventually this degradation will result in excessive hot spots in the core that will affect the life of the stator winding. Second, the winding currently installed in the units does not have the same connections that unit 2 has. This means the vibration levels are much larger in these units compared to unit 2. These higher vibration levels would likely severely stress the water boxes on the winding affecting life and possibly resulting in leakage.

The existing circuit rings, stator core, rotor and pure water systems have the same limitations as option 1 stated up above for U2 using the existing windings installed in 2020.

Voith would not recommend uprating these units unless the cores are replaced, and the winding is replaced with the design currently installed in unit 2. This would also include the new water box design to minimize vibrations.

4.2 Thrust Bearing Load Capacity

Voith Hydro uses software called Combros-A to study bearings. This software is the industry standard used for bearing analysis used in Germany. It has been developed by the ITR Institute of the Clausthal-Zellerfeld University, ordered by the FVA. The FVA is a large German Community for Research and development.

The thrust bearing at Helms is unique that the bearing pads are water-cooled [REDACTED]

[REDACTED] The pads are supported on an adjustable piston that allows the pads to tilt during operation in turbine and motor modes of operation.

During the setup of the bearing model, some assumptions had to be made since this pad design is quite unique and not common in the hydro industry. Reference the provided presentation and report for complete details of the model and assumptions. As a result of the analysis Voith concluded that the bearing can safely operate up to rated loads up to [REDACTED] and transient loads of [REDACTED]. These values assume the same water-cooling arrangement currently in place [REDACTED]

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4.3 Stator Core Buckling Analysis

Voith Hydro uses internal proprietary calculation software to analyze the stator core for buckling. Buckling occurs when the stator core expands against the stator frame due to thermal affects. Magnetic pull forces can also contribute to core buckling. Buckling can be seen in the core when the thin laminations are no longer flat but instead take the shape of a wave. Buckling can have long term effects on the stator winding as well as the insulated lamination sheets making up the stator core.

Using the input data available Voith was able to successfully analyze the stator core buckling for U2 as it is currently (450 MVA) and the uprated machine (572 MVA).

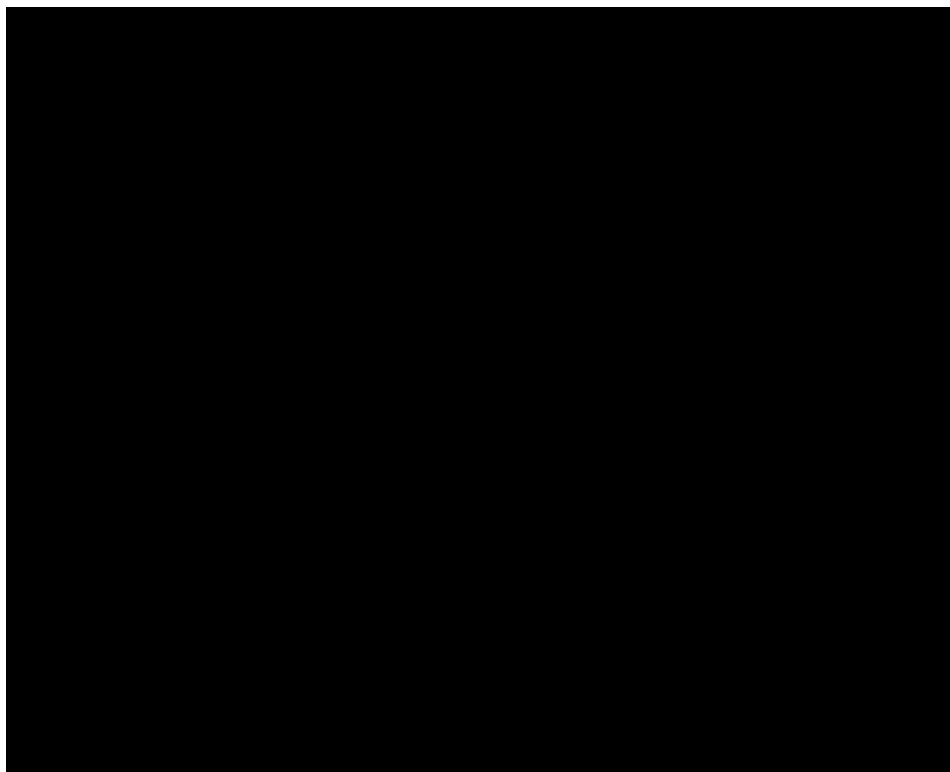
Voith assumed the stator core clamping pressure [REDACTED] this is a normal value for Voith Hydro and close to industry standard for most hydro generators. [REDACTED]

[REDACTED] the calculated safety factor was found to be 2.8. This factor exceeds the Voith guideline of 2; so, it indicates that the existing stator core will likely not exhibit buckling. During the rewind in 2020 Voith did not see signs of core buckling.

4.4 Stator Core Clamping

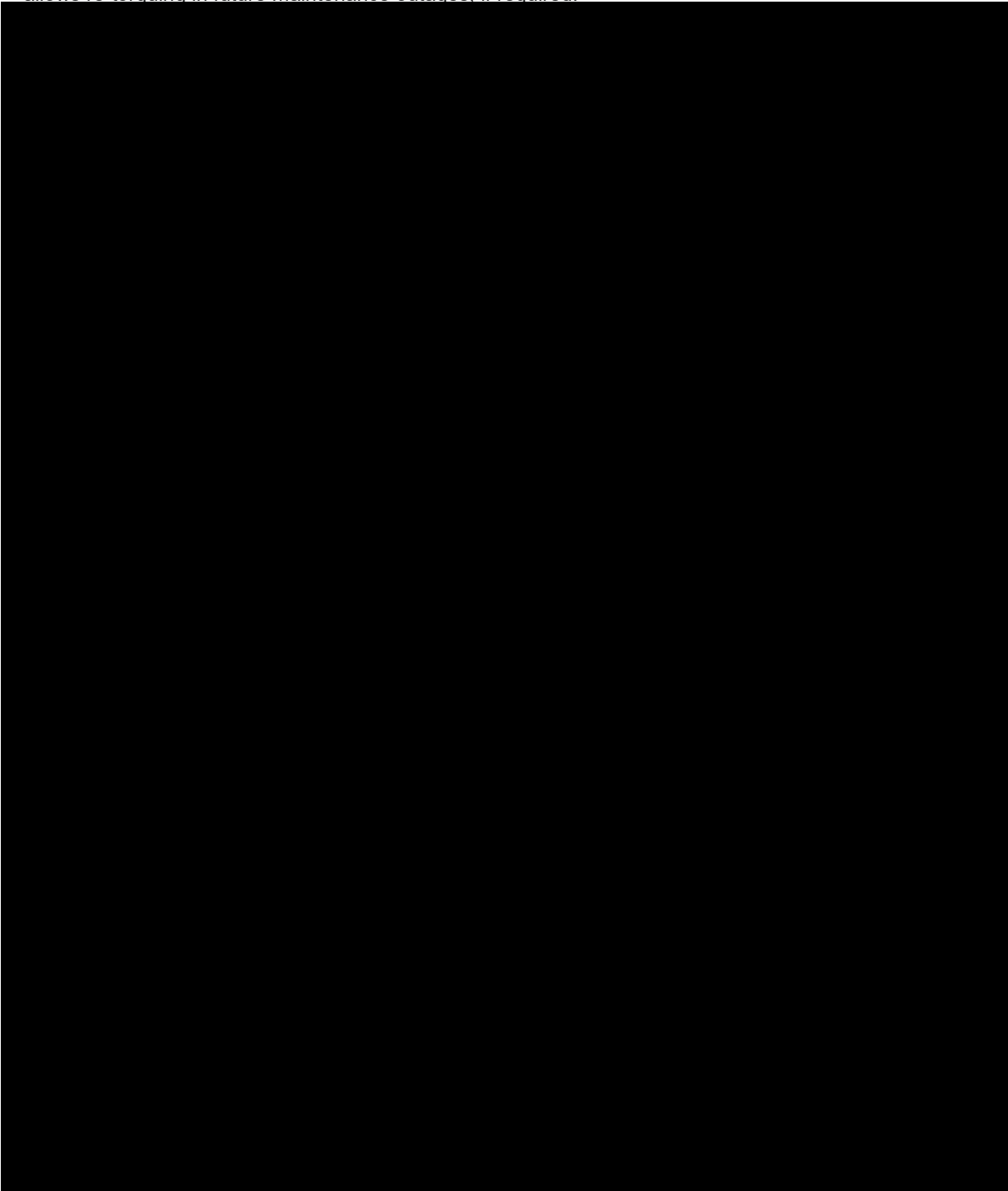
The OEM design consists of the stator core laminations being stacked tight against the key bars. The key bars are then welded directly to the stator frame. This arrangement eliminates any opportunity for the stator core to freely expand during operation. It also limits the core compression which over time allows the core to settle and become loose.

Voith performed a calculation using the worst-case failure condition for the radial forces each key bar would see during a failure condition. Results indicated that the stress in the welds between the frame and keybars would slightly exceed Voith recommended values. This should be looked at further in the future for weld size but based on the values only being slightly above allowable there would be no concern.



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If PG&E would elect to replace the stator core based on age and condition, a new Voith clamping system is recommended. The Voith design is the proven standard double dovetail system allowing free thermal expansion between core and frame, avoiding the binding of the laminations to stator frame keybars. Along with replacement of the stator core, the standard Voith clamping system is also recommended to maintain constant core compression and allow for free thermal expansion of the core during operation. This system allows re-torquing in future maintenance outages, if required.



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An advantage of the standard Voith clamping system design: because it maintains the constant compression via the spring washers, it's better than the OEM design at compensating for vibration and settling of the core.

The core compression is established and made equal at all clamping bolts by measuring deflection of the spring washers (rather than applying a specific torque value to the nut). This results in more equally distributed pressure around the core and the ability to measure the compression along the unit life.

The radial expansion free will provide sufficient safety against core lamination buckling.

4.5 Radial Dowels (frame to sole plate)

Using the failure torques of the machine at the uprated power Voith performed calculations to check if the existing radial dowels installed between the stator frame and embedded sole plate is sufficiently sized. The number of dowels is [REDACTED] and the diameter as seen on the drawings is [REDACTED]. The results indicate that the shear stress in the dowel and compression stress in the frame and soleplate exceeds Voith design guidelines. To reduce the stresses to allowable levels, the doweling area would [REDACTED].

4.6 Generator Brakes

Using Voith developed tools to calculate braking of the generator, the existing brakes installed in the Helms generators were studied to determine if they are adequate. In order to perform this calculation Voith had to rely on some data from the existing supplier of the runner to estimate the residual runner torque. Using this information Voith assumed leakage values into the water passage based on new conditions and worn-out conditions. The results indicate that the time to stop the unit with leakage considered in a new machine is acceptable but in the worn-out condition, the brakes are not adequate. It should be noted the PG&E generally does not stop using the brakes but uses electrical braking instead. The calculations also found that the temperature of the brake ring is excessive during the braking operation.

4.7 Shaft Line Analysis

The purpose of this analysis is to study the dynamic and static behavior of the shaft line of the unit. The shaft line includes the runner, all existing shafts, generator rotor, and the exciter. The calculations performed were as follows: critical bending speed and bending line of the shaft system. These calculations are done using software called HyMADYN 2. It is important to note that Voith used our internal standards for bearing and structure stiffness since detailed FEA analysis would be required to estimate actual stiffness values. Any modifications made to the machine structure in the past by other suppliers or PG&E have not been captured in these calculations. Results indicate that the first critical bending speed is only 1.2 times above the rated speed of 360 RPM. Voith design guidelines requires a values of 2 or more to be acceptable.

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Results indicate that Helms units are likely operating under high vibrations. [REDACTED]

[REDACTED] A further detailed study should be performed to capture the design of the machine as it is operating today and to determine actual bearing stiffnesses. [REDACTED]

4.8 Shaft Stress Calculation and Coupling Calculation

Voith performed calculations to determine if the stresses in the shafts and shaft couplings are acceptable for continued operation for at the possible uprated power of 572 MVA.

The results indicate that the shear stress for the turbine shaft exceed Voith guidelines for uprated power. Voith recommends shear stress to be [REDACTED] the results indicate a shear stress of [REDACTED] To meet the [REDACTED] guideline, the maximum uprate would be limited to 535 MVA. For simplicity, details such as residual unbalance and bearing radial loads were not considered at this time. Voith recommends a more detailed analysis including FEA analysis be performed to fully understand the high stressed areas of the shafts. A fatigue study is also recommended.

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5 Conclusions

The series of calculations described above and covered in full detail in individual presentation preliminarily indicate that the existing Helms U2 can reach an uprate to 520 MVA and the following:

- The maximum uprate potential of 572 MVA to match the hydraulic turbine is not possible due to restrictions caused by the pure water system.
- If modifications are made to the pure water system and the winding hydraulic circuit and the stator core is replaced U2 can reach a maximum uprate of 572 MVA. It should be noted that the rotor temperature rise is likely to exceed class F temperature at this rating.
- A close investigate of the circuit ring arrangement would be required to ensure proper magnetic distances.
- The existing stator core is of a concern due to the extensive repairs required in 2020 and performed by Voith to re-use the core and limit the hot spots during loop testing. Voith recommends replacing the existing core with a modern VH fixation and clamping system with dovetails to allow free thermal expansion and Belleville washers to keep constant pressure on the core. The new core can be continuously staked to improve safety margins against buckling and improve overall roundness.
- The shaft line analysis showed that the potential for high vibration exists for the Helms units. A further investigation must be performed on the existing upper bearings and structures to determine actual stiffnesses and to develop a plan on how to increase the critical bending speed.
- Diameter of dowels shall be increased to match the required uprate power.

Units 1 and 3 have the same limitations as unit 2 but the stator winding has less copper compared to the stator winding currently installed in unit 2. This results in higher hot water-cooling temperatures. To lower the hot water temperature, these units as they are today could reach a maximum uprate of 481 MVA electrically and thermally but as mentioned in section 4.1 above there are other areas to consider. Voith does not recommend uprating these units as they are today above the current rating of 390 MVA.

PG&E also requested Voith evaluate unit 2 at 460 MW @ a pf of 0.90 (i.e. 511 MVA). This request was made after the study was completed. The results were added to the electromagnetic study. The results are summarized in the table below.

Existing Unit 2		Operation @ 460 MW / PF0.90	Remarks:
Stator winding (bars)	Voith Hydro (Re-wound 2018)	OK	Necessary to confirm pure water system capacity
Stator winding (circuit rings)	OEM Westinghouse (1984) Re-insulated	To be confirmed	Limited by magnetic Induction (Existing temperatures have to be measured)
Stator core	OEM Westinghouse (1984)	OK	Can be limited by the existing core condition
Rotor	Alstom (Replaced 2015)	NOT OK for Class B rise (Remark: For information only since rotor is not part of Voith evaluation scope)	The field current is 2797 A from Voith simulation, corresponding to 84 K rise acc.to curve in Alstom measurement report (slide 14), then exceeding the Class B rise. (Existing rotor winding temperature has to be measured and confirmed)
Pure water	OEM Westinghouse (1984)	To be confirmed	Necessary to confirm pure water system capacity

GENERATOR Uprate study executive summary	HELMS U1-3	
Technical Report	Doc ID:	2-10276992
	Doc. Rev.:	-

6 Recommendations

Based on this uprated study Voith recommends the following:

1. Further investigate of the pure water system and its design and limitations.
2. 3D modeling and FEA of the bearing structures to determine the bearings stiffness.
3. Perform a more detailed shaft line analysis followed by possible scenarios on how to improve the shaft line stability and increase the critical bending speed.
4. 3D modeling, FEA and fatigue study of the shaft system to determine peak stresses.
5. FEA analysis of the existing stator frame for structural integrity and to accommodate the new clamping system.
6. Perform detailed NDE inspection on all major components to confirm the suitability for the remaining life evaluation according to the FEA calculations.
7. Investigate possibility to replace the existing rotating exciter with a static exciter to improve vibration performance and response to the grid.
8. Perform ventilation/air flow detailed analysis to confirm pole temperatures.
9. Perform hydraulic studies to confirm turbine uprate limits.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT D

GE ROTOR STUDY



GE Renewable Energy Hydro

ENGINEERING

Project:

HELMS PROJECT

Title:

GENERATOR ROTOR VERIFICATIONS UNDER A POWER INCREASE

Ref. number:

24412500MKB20-200FED-01

Summary:

Reference Document:

Client : Pacific Gas and Electric Company

GE Ref. N°:

SFPUC Ref. N°:

Ref. :

Code Distribution : I – O – Q – Customer

GE CONFIDENTIAL

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(*) Available Status: PRE: Preliminary, GFR: Good For Review, GFE: Good For Execution



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1 SCOPE AND RANGE OF VALIDITY

The Units of Helms Pumped Storage Plant are currently subjected to engineering verifications to increase the power output by 60 MW for each Unit, from 448.5 MVA to 516 MVA.

This document, focussing on the existing Generator Rotor, presents the results and conclusions of the feasibility study aimed at determining if the Generator components are robust enough to withstand this increase of the power output.

It is important to precise that GE has received the information that the expected power increase will not impact the unit rotation speeds, and thus the synchronous speed, the load rejection speed and the runaway speed remain unchanged. It was also specified that this power increase will not significantly impact the hydraulic thrust. From a mechanical perspective, the power increase would lead to an increase of the magnetic torque and thermal heating of the electrical Generator Rotor components.

The existing Generator Rotor were supplied by GE in 2013. This document presents the analysis performed using GE's inhouse generator design software to evaluate the electrical limitations (temperature, magnetic flux, excitation current) on the rotor components as listed below.

- | | |
|----------------------------------|--------------------------------|
| • Section 3.1: Pole coil | Temperature increase |
| • Section 3.2: Pole core and rim | Increase in magnetic flux |
| • Section 3.3: Excitation system | Increase in excitation current |

Based on GE's calculations and engineering reports presenting the results of the mechanical assessments that were done for the existing Generator Rotor, the components most affected by the power increase have been studied either by analytical calculations or by Finite Element Analysis. The studies components are listed as follow:

- | | |
|---------------------------------------|-----------------------------|
| • Section 4.1: Rotor Spider: | Increase of magnetic torque |
| • Section 4.2: Rotor Pole End Plate: | Increase of magnetic torque |
| • Section 4.3: Rotor Pole Lamination: | Increase of magnetic torque |
| • Section 4.4: Rotor Pole Damper Bar: | Temperature increase |
| • Section 4.5: Rotor Rim: | Increase of magnetic torque |
| • Section 4.6: Generator Shaft: | Increase of magnetic torque |
| • Section 4.7: Rotor Lower Coupling: | Increase of magnetic torque |

2 REFERENCE DOCUMENTS

H-822600 MKB 24-201 F ED-01rev1	Rotor Spider FEA Assessment
H-822600 MKB 26-200 F ED-02	Rotor Pole End Plate FEA
H-822600 MKB 26-200 F ED-03	Rotor Pole Lamination FEA
H-822600 MKB 23-011 F ED-01	Lower Rotor Coupling Calculations
H-822600 MKB 25-001 F ED-01	Rotor Rim Calculations
H-822600 MKB 25-001 F ED-03	Rotor Rim Fatigue Calc at the pole attachment area
H-822600 MKB 26-201 F TL_01revD	Pole Core Assembly Drawing



3 ELECTRICAL ASSESSMENT

An assessment of the rotor components was made to evaluate the effect of an increase in output power from 448.5 to 516 MVA. The electrical analysis, performed using GE's inhouse generator design software covered the effect on temperature increase, change in magnetic flux saturation as well as expected increase in excitation current.

The existing generator is rated as follow based on nameplate data (Generator)

CHARACTERISTIC	UNIT	VALUE
Maximum apparent power	KVA	448 000 (Generator) 385 700 (Motor)
Armature voltage	kV	18
Power Factor	-	0.90
Speed	RPM	360
Field current	A	2540 (Generator), 2340 (Motor)
Field voltage	V	220 (Generator), 202 (Motor)
Maximum temp. rise rotor	°C	80
Maximum cooling air temp.	°C	40

Table 1 Relevant existing unit characteristics

3.1 ROTOR COIL

Heat run tests were performed by GE on all 3 units between 2015 and 2016, providing measured average rotor winding temperature rises and excitation currents at the maximum apparent power (448.5 MVA). The table below presents the measured and calculated values. The excitation current evaluated by the latest version of GE design software is close to the measured values. Since measurements show large variations in rotor temperature rises between units, the calculated temperature rises were calibrated on what was measured for each unit. This increased the accuracy of the model for each unit. GE then increased the power output in the simulation to evaluate the temperature rise at 516 MVA, 0.9 P.F. Table 2 sums up the results. The field current densities (there are 2 types of copper conductors) remains in the normal range at 516 MVA but the temperature rises are high.

CHARACTERISTIC	MEASURED AT 448.5 MVA, 0.9 P.F.	CALCULATED AT 448.5 MVA, 0.9 P.F.	CALCULATED AT 516 MVA, 0.9 P.F.
Rotor excitation current	U1 2547 A U2 2540 A U3 2547 A	2545 A	2761 A
Current density	2.28 A/mm ² and 2.77 A/mm ²	2.28 A/mm ² and 2.77 A/mm ²	2.47 A/mm ² and 3.00 A/mm ²
Rotor winding average temperature rise (temp. if 40 C cold air)	U1: 65.6 K (105.6 C) U2: 67.5 K (107.5 C) U3: 75.7 K (115.7 C)	U1: 65.6 K (105.6 C) U2: 67.5 K (107.5 C) U3: 75.7 K (115.7 C) (above are calibrated)	U1: 81 K (121 C) U2: 83 K (123 C) U3: 93 K (132 C)
Maximum rotor copper temperature rise (temp. if 40 C cold air)	-	U1: 80 K (120 C) U2: 81 K (122 C) U3: 92 K (132 C)	U1: 98 K (138 C) U2: 100 K (140 C) U3: 113 K (153 C)

Table 2 Excitation current and rotor temperature rises



Figure 1 and 2 illustrate the temperature rise on each side of the pole. The maximum temperature is found on the lee side (the side away from the facing wind) when the unit is generating power (highest excitation current). The temperature rises extrapolated at 516 MVA are above the nameplate 80 K rise and the absolute temperatures are too close to the limit of the existing pole insulation system, rated 155 C.



Fig. 1 Temperature distribution on the Luff and Lee side 516 MVA, 0.90 PF with 40 C cold air

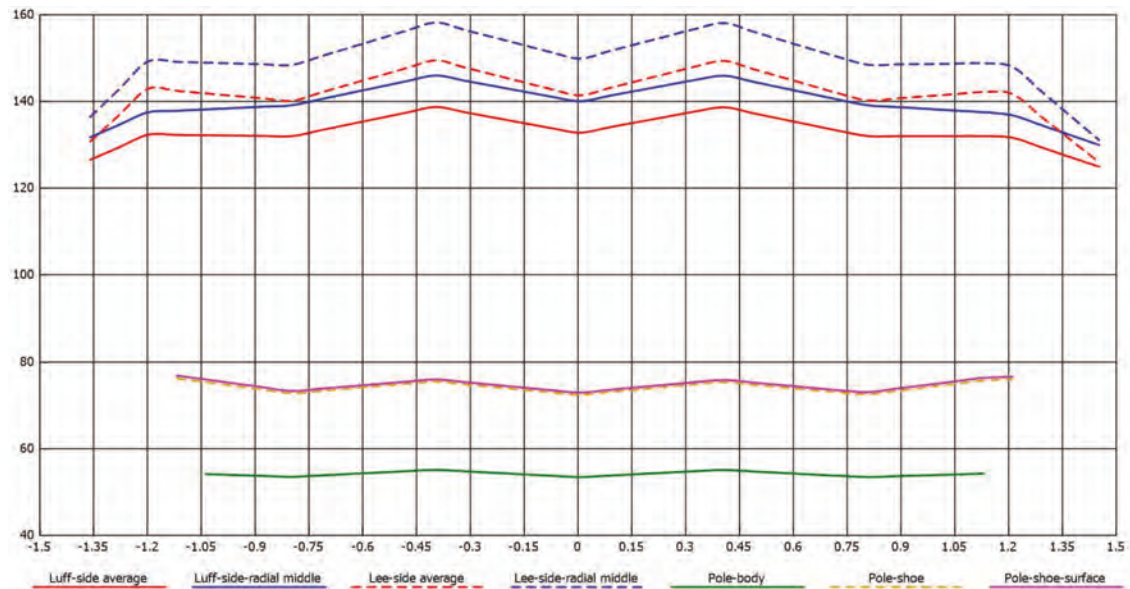


Fig. 2 Temperature distribution on the pole at 516 MVA, 0.90 PF with 40 C cold air

The theoretical life of electrical insulation is approximately doubled for every 8-10°C decrease in temperature based on the Arrhenius curve. Figure 3 below shows the Arrhenius curve of the pole Nomex turn insulation. This curve, which helps to explain the relationship between temperature and ageing, does not consider the epoxy resin between layers that cannot withstand as much temperature.

Since such machines have long life expectancy, large generators with 155°C rated insulation are usually designed to operate with temperature rises associated with class B (below 130°C). For example, a temperature rise of 80 K is usual for rotor winding operating with 40°C cold air. Operation with lower operating temperature rises help to increase the life expectancy of the rotor windings. In addition to the effect of high temperature on ageing, significant pole coil thermal expansion and retraction during starts and stops can lead to mechanical fatigue of the pole-to-pole connections or of the rotor winding end connections.



For units that are subjected to frequent cycling loading and can be started more frequently than twice per day like Helms, IEEE C50.12 recommends reducing temperature rises by 5-10°C. To get the same life expectancy as units not subjected to cycling the target maximum temperature rise can be around 70-75 K based on GE's interpretation of this recommendation. Unit 1 is already operating at this limit with 448.5 MVA generator output. At 516 MVA there is practically no margin with what the turn insulation (epoxy + Nomex) can withstand for only a few years, with average calculated temperature between 138 and 153°C. We therefore conclude that the existing pole coils can not operate at 516 MVA, 0.90 PF.

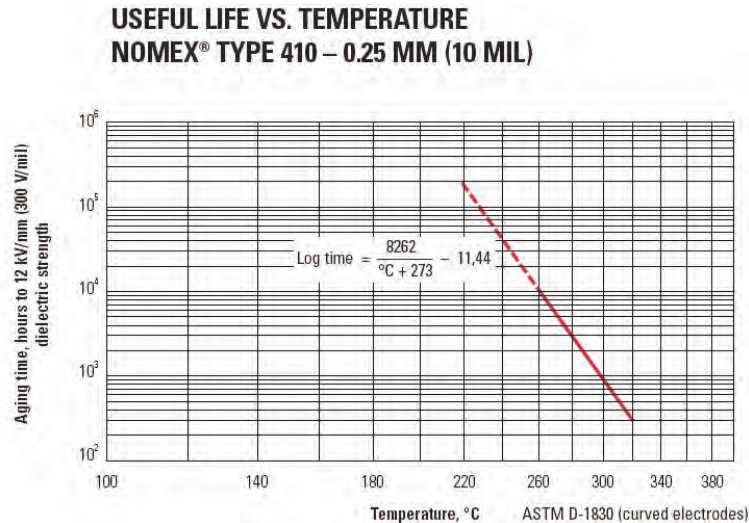


Figure 3 Rotor Nomex turn insulation Arrhenius curve

3.2 ROTOR CORE AND RIM

The pole core and rim flux densities were evaluated to verify magnetic flux saturation levels.

Since the resultant magnetic flux density in the air gap remains unchanged (the generator output voltage is unchanged), the magnetic pull per pole remains the same. GE assumes that the stator core remains the same: a stator core or air gap modification may affect the magnetic pull per pole.

To compensate the higher stator armature reaction at 516 MVA, the magnetic flux in the pole increases slightly to produce the same resultant flux in the air gap. Refer to Table 2 which compare the magnetic flux densities at 448.5 and 516 MVA. Since the pole body is relatively saturated by magnetic flux, within normal range of flux densities but closer to the maximum permissible, a small variation in magnetic flux density in the pole core can have more influence on the calculated excitation current. All rotor calculated magnetic fluxes remain under maximum permissible values. The pole core and rotor rim dimensions remain acceptable at 516 MVA, 0.90 P.F. from a magnetic saturation standpoint. An analysis would be required to determine if it would be advantageous to optimise both the pole core and pole coil simultaneously to help lower the coil temperatures.

A higher generator output leads to a proportionally higher requirement for negative sequence current (15% higher). The higher requirement would lead to a temperature 32% higher than at 448.5 MVA. With a I_2^2t of 20 seconds at 516 MVA, the damper bar temperature would be around 156°C. The damper bar winding would expand during a short-circuit more than the space available: this may damage the core. Refer to section 4.4. I_2^2t would need to be no more than 18 to avoid contact between the damper bar and pole end plate.



MAGNETIC FLUX DENSITIES	FLUX DENSITIES AT 448.5 MVA, 0.9 P.F.	FLUX DENSITIES AT 516 MVA, 0.9 P.F.
Rotor rim	0.46 T	0.47 T
Pole body	1.78 T	1.81 T
Pole Shoe	1.42 T	1.43 T
Air gap	1.10 T	1.10 T

Table 3 Rotor components' flux densities

3.3 EXCITATION CURRENT

The excitation data from the 2012 refurbishment specification list the following characteristic for the existing excitation system.

Exciter Data

Make: ABB
Model: A5T-0/U521-S4200
XFMR: 13.8 kV / 460 V
Vmax output: 380 Vdc
I rated output: 2948 Amps dc
Imax: 3990 Amps dc @ 60 sec.

Operation at 516 MVA, 0.90 P.F. at overvoltage condition would lead to an excitation current close to the limit of the excitation system. In practice there can be some variations versus what is calculated. The excitation voltage increase (214 to 232 V) will reduce somewhat the response time. The excitation system may still be acceptable, but the margin is small. The rotor coil temperature rises with Un+5% stator output voltage would be between 144 and 160°C. The temperature is above class F.

OPERATING CONDITION	MEASURED EXCITATION CURRENT	CALCULATED EXCITATION CURRENT
448.5 MVA, 0.9 P.F., 18 kV	2440-2447 A	2445 A
448.5 MVA, 0.9 P.F., 18.9 kV	-	2660 A
516 MVA, 0.9 P.F., 18 kV	-	2761 A
516 MVA, 0.9 P.F., 18.9 kV	-	2873 A

Table 4 Excitation current at different operating conditions



4 MECHANICAL ASSESSMENT

The same approach was used for this mechanical study in order to assess whether the component is robust enough to undergo a power increase of 15%, or an additional 60 MW.

First of all, a complete review of the existing GE's engineering reports related to the existing Generator Rotor is made in order to assess the safety margin available for each Generator Rotor component affected by the increase in power.

In all cases, the study focuses on the regions of interest most solicited under nominal operating conditions. The study will compare the static stresses before and after the power increase as well as the fatigue resistance for stop-start cycles.

4.1 ROTOR SPIDER MECHANICAL ASSESSMENT

The Finite Element Model used to evaluate the rotor spider design, presented in the Rotor Spider Finite Element Analysis *H-822600 MKB 24-201 F ED-01rev1*, was updated to assess the impact of a power increase of 15%, or an additional 60 MW. This translates to an increase of the magnetic torque applied on the rotor spider.

The static stress results comparison, presented in APPENDIX A, showed that the static stresses during nominal operation @ 403.65 + 60 MW are below the static stress criterion defined in section 5 of the Rotor Spider Finite Element Analysis *H-822600 MKB 24-201 F ED-01rev1*.

The fatigue cumulative damage assessment, presented in APPENDIX A, showed that the allowable number of start-stop cycles is reduced to 57 436 instead of 83 449 due to the 60 MW power increase, according to the FKM Guide methodology. For reference, this new allowable number of start-stop cycles still respect the criteria defined in the initial technical specification which was three start-stops per day for 50 years.

To conclude this section, the existing Rotor Spider is fit, without modification, to operate safely under the expected power increase.

4.2 ROTOR POLE END PLATE MECHANICAL ASSESSMENT

Using the results presented in the Rotor Pole End Plate FEA Study *H-822600 MKB 26-200 F ED-02*, the stresses obtained are adjusted to take into account a power increase of 15%, or an additional 60 MW.

The static stress results comparison presented in APPENDIX B showed that:

- The static stress at Point 2 (Refer to TABLE V from *H-822600 MKB 26-200 F ED-02*) is increased by less than 1%;
- The static stress at Point 3 (Refer to TABLE V from *H-822600 MKB 26-200 F ED-02*) is increased by less than 1%.

The static stresses during nominal operation @ 403.65 + 60 MW are below the static stress criterion defined in section 5 of the Rotor Pole End Plate FEA Study *H-822600 MKB 26-200 F ED-02*.



Additionally, using the peak stress at Point 3 ($P_m + P_b + Q + F$), the alternate stress in the transition radius is increase by a marginal 1 MPa. Using the results presented in TABLE VII of the Rotor Pole End Plate FEA Study *H-822600 MKB 26-200 F ED-02*, this would translate in a negligible cumulative fatigue damage increase due to the 60 MW power increase. For reference, this new allowable number of start-stop cycles still respect the criteria defined in the initial technical specification which was three start-stops per day for 50 years.

To conclude this section, the existing Rotor Pole End Plates are fit, without modification, to operate safely under the expected power increase.

4.3 ROTOR POLE LAMINATION MECHANICAL ASSESSMENT

Using the results presented in the Rotor Pole Lamination FEA Study *H-822600 MKB 26-200 F ED-03*, the stresses obtained are adjusted to take into account a power increase of 15%, or an additional 60 MW.

The static stress results comparison presented in APPENDIX C showed that:

- The static stress at Point 2 (Refer to TABLE V from *H-822600 MKB 26-200 F ED-03*) is increased by less than 1%;
- The static stress at Point 3 (Refer to TABLE V from *H-822600 MKB 26-200 F ED-03*) is increased by less than 1%.

The static stresses during nominal operation @ 403.65 + 60 MW are below the static stress criterion defined in section 5 of the Rotor Pole Lamination FEA Study *H-822600 MKB 26-200 F ED-03*.

Additionally, using the peak stress at Point 3 ($P_m + P_b + Q + F$), the alternate stress in the transition radius is increase by a marginal 0.5 MPa. Using the results presented in TABLE VII of the Rotor Pole Lamination FEA Study *H-822600 MKB 26-200 F ED-03*, this would translate in a negligible cumulative fatigue damage increase due to the 60 MW power increase. For reference, this new allowable number of start-stop cycles still respect the criteria defined in the initial technical specification which was three start-stops per day for 50 years.

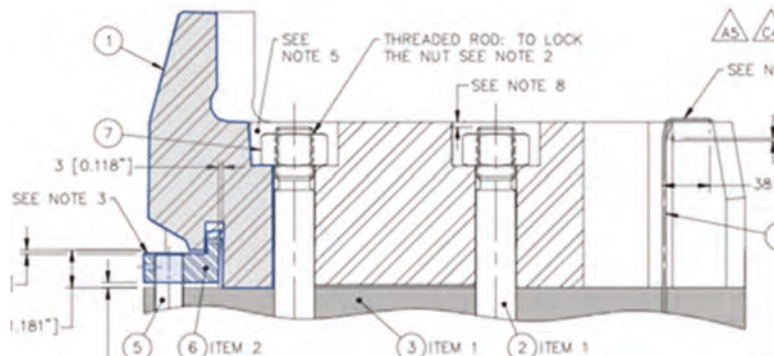
To conclude this section, the existing Rotor Pole Laminations are fit, without modification, to operate safely under the expected power increase.

4.4 DAMPER BAR MECHANICAL ASSESSMENT

Based on the rotor pole dimensions shown in drawing *H-822600 MKB 26-201 F TL_01revD*, using the clearance between the tip of the damper bar and the bottom surface of the rotor pole end plate, Appendix D shows the maximum allowable temperature rise before the damper bar interferes with the rotor pole end plate is around 143 °C. Based on the electrical assessment presented in section 3, the damper bar maximum expected temperature rise from a power increase of 15%, or an additional 60 MW is around 156 °C for a I_2^2t of 20 sec, already under the standard 40 seconds.

The pole pressure plate / pole shoe design may be modified with an opening next to the damper short circuit bar to allow for additional expansion of the damper bars during long abnormal transient events (eg. short circuits). The damper bar short circuit bar (in blue below) would also need to be modified. This solution would need to be validated.

Adding damper connections between poles would not reduce the damper bar's expansion. Bigger damper bars would be cooler and expand less.



To conclude this section, with the current damper bar design, there is a risk that the temperature increase related to the power increase leads to damage the Rotor Pole. Local modifications of the Rotor Poles are recommended to ensure safe operation of the units under the expected power increase. Any modifications would need to be validated.

4.5 ROTOR RIM MECHANICAL ASSESSMENT

4.5.1 POLE ATTACHMENT AREA

The T-tail cut-out transition radius of the rotor rim pole attachment area is usually a critical area. It is assumed that the stresses at that location resulting from the rotor pole centrifugal loads are equal or lower than what is evaluated for the pole T tail. As demonstrated in section 4.2 of the current report, a power increase of 15% is responsible for a marginal static stress and cumulative fatigue damage increase in the rotor pole end plate attachment area. It is assumed that a power increase of 15%, or an additional 60 MW with not have any detrimental impact on the rotor rim pole T-tail attachment area.

4.5.2 ROTOR RIM KEY

Using the results presented in the Rotor Rim Calculation Report H-822600 MKB 25-001 F ED-01, Appendix E shows that the Rotor Rim key bearing stress and shear stress results during nominal operation @ 403.65 + 60 MW are below the criteria presented in section 7.4 of the Rotor Rim Calculation Report H-822600 MKB 25-001 F ED-01.

To conclude this section, the existing Rotor Rim is fit, without modification, to operate safely under the expected power increase.

4.6 GENERATOR SHAFT MECHANICAL ASSESSMENT

During the refection work in 2013, the original turbine and Generator Shafts were not refurbished. In order to assess whether the shafts are robust enough for a power increase of 15%, or an additional 60 MW, the torsional stress in the generator shaft is evaluated in Appendix F.

Torsional stresses analytically calculated for the original power and the increased power are then compared to a targeted value commonly used in shaft design for hydropower units, which is that the torsional stresses under only the torque load should be equal or lower than 41 MPa.

- Generator Shaft Torsional stresses at 403.65 MW are around 45.1 MPa, exceeding the stress target by 10%;



- Generator Shaft Torsional stresses at 463.65 MW are around 51.7 MPa, exceeding the stress target by 26%.

These results show that Generator Shaft, even before and after the power increase, operates at less safety margin as commonly targeted in usual hydropower units.

To conclude this section, the current mechanical verification shows that existing Generator Shaft is further solicited in torsion than what is usually targeted. Considering this, a complete Generator Shaft FEA calculation using the actual methodology and criteria should be performed on the existing Generator Shaft to confirm its structural integrity related to this power increase.

4.7 ROTOR LOWER COUPLING MECHANICAL ASSESSMENT

During the refecton work in 2013, in order to compensate the deviation between original shear sleeves positions and the new refurbished rotor spider lower coupling bores, eccentric sleeves were used instead of the original shear sleeves.

Using the results presented in the Lower Rotor Coupling Calculation Report *H-822600 MKB 23-011 F ED-01*, Appendix G showed that the Rotor Lower Coupling Eccentric Sleeve bearing stress results during nominal operation @ 403.65 + 60 MW are below the criteria presented in section 5.2 of the Lower Rotor Coupling Calculation Report *H-822600 MKB 23-011 F ED-01*.

To conclude this section, the existing Rotor lower coupling parts are fit, without modification, to operate safely under the expected power increase.



5 CONCLUSION

Engineering verifications has been performed in the existing Helms Generator Rotor to determine if this component is robust enough to withstand an increase of the power output of each unit by 60 MW.

Using the existing GE's calculations and engineering reports presenting the results of the mechanical assessments that were done in 2013 for the existing Rotor supplied, as well as electrical calculations using a virtual model of the generator, the results show that:

- The Rotor Spider, the Rotor Rim and the Rotor lower coupling are robust enough to withstand a power increase of 15%;
- The calculated pole coil temperature would be too high at the uprated output; the pole design would need to be modified to stay within acceptable temperature rise;
- The excitation current calculated at 516 MVA is close to the maximum rating of the excitation system.
- Although that the Rotor Pole End Plates and the Rotor Pole Laminations are robust enough to withstand this power increase, Rotor Poles should be modified since the current damper design is not adequate for the expected temperature rise related to this power increase;
- Generator Shaft is further solicited in torsion than what is usually targeted. Considering this, a complete Generator Shaft FEA calculation using the actual methodology and criteria should be performed on the existing Generator Shaft to confirm its structural integrity related to this power increase.

This document demonstrated that Helms Generator Rotor could not undergo a power increase unless certain modifications are made which would be established in subsequent studies. Therefore, the maximum MVA value achievable without further study and modification is 448.5 MVA.



**APPENDIX A
ROTOR SPIDER STATIC STRESS RESULTS COMPARISON**



Rotor Spider Points of Interests

As a reminder, Figure 2 extracted from the Rotor Spider Finite Element Analysis report *H-822600 MKB 24-201 F ED-01rev1* shows the interest points where stresses are evaluated.

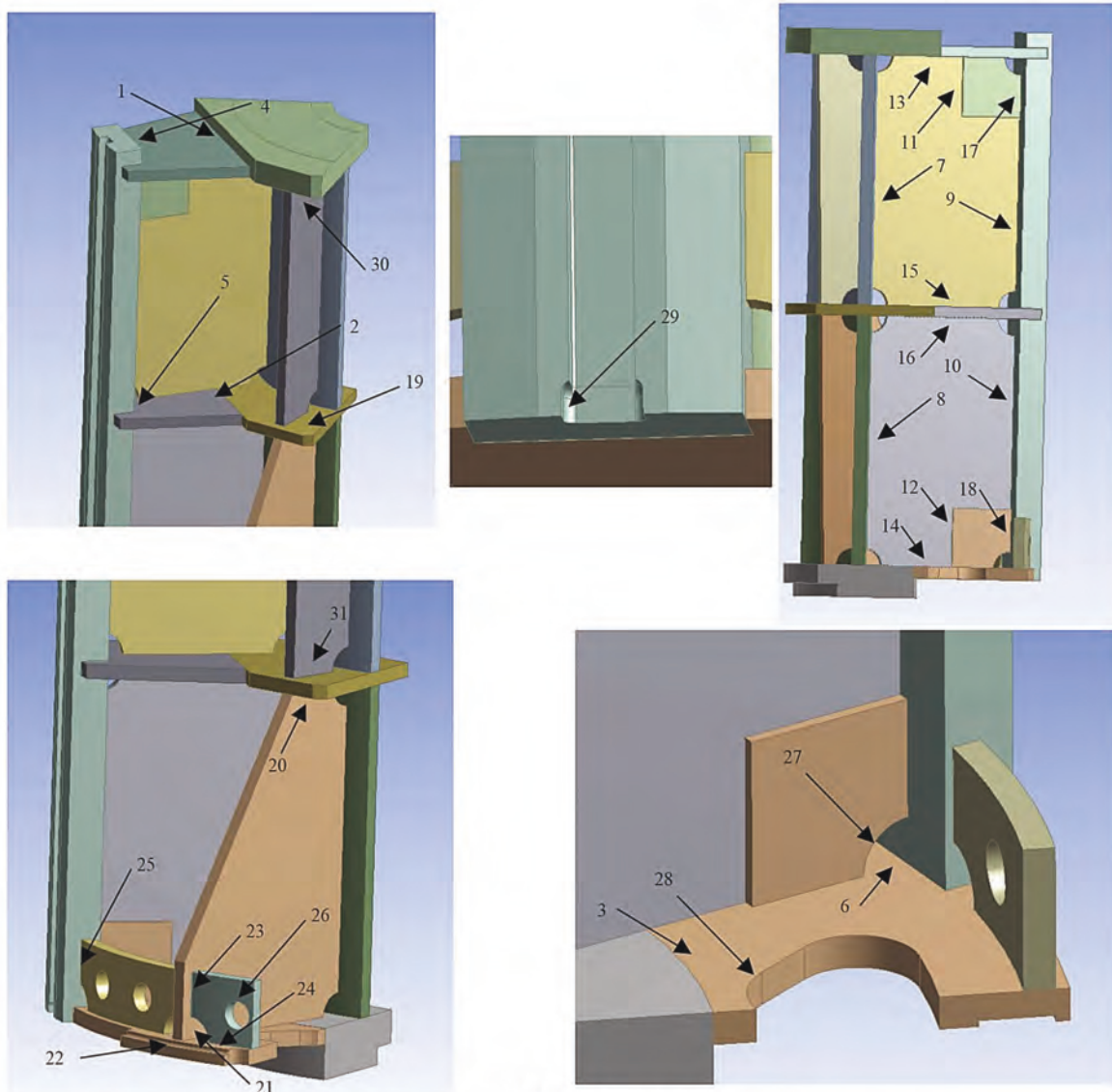


Figure 2: Interest Points



Rotor Spider Static Stress Result Comparison

The nominal operation static Von Mises stresses from TABLE VII of the Rotor Spider Finite Element Analysis report *H-822600 MKB 24-201 F ED-01rev1* are compared to the Von Mises static stresses from the nominal operation load case with an additional 60MW. The same numerical model is used to evaluate the static stresses from the Power increase load condition.

The results are discussed in section 4.1.

ROI	STRESS CATEGORY	NOMINAL OPERATION 448.5 MVA 403.65 MW	NOMINAL OPERATION 515.2 MVA 463.65 MW		STATIC STRESS CRITERIA
1	P _L	22	25	16%	135
	P _L + P _B	41	45	9%	135
2	P _L	25	25	-1%	135
	P _L + P _B	33	34	3%	135
3	P _L	58	65	12%	135
	P _L + P _B	70	80	14%	135
4	P _L	15	14	-10%	135
	P _L + P _B	28	28	-1%	135
5	P _L	20	19	-6%	135
	P _L + P _B	27	26	-4%	135
6	P _L	13	14	6%	135
	P _L + P _B	47	53	12%	135
7	P _M	18	18	-1%	90
	P _M + P _B	21	21	1%	135
8	P _M	19	19	1%	90
	P _M + P _B	31	32	5%	135
9	P _L	15	15	3%	135
	P _L + P _B	18	18	3%	135
10	P _L	17	17	-2%	135
	P _L + P _B	19	18	-4%	135
11	P _L	25	26	2%	135
	P _L + P _B	26	26	0%	135
12	P _L	18	19	4%	135
	P _L + P _B	38	43	12%	135
13	P _L	26	26	1%	135
	P _L + P _B	27	28	3%	135
14	P _L	26	26	1%	135
	P _L + P _B	37	39	5%	135
15	P _M	20	21	3%	90
	P _M + P _B	21	22	3%	135
16	P _M	19	19	3%	90
	P _M + P _B	23	24	2%	135



ROI	STRESS CATEGORY	NOMINAL OPERATION 448.5 MVA 403.65 MW	NOMINAL OPERATION 515.2 MVA 463.65 MW		STATIC STRESS CRITERIA
17	P _L	15	15	3%	135
	P _L + P _B	18	18	1%	135
18	P _L	13	13	-1%	135
	P _L + P _B	20	22	8%	135
19	P _M	33	32	-3%	90
	P _M + P _B	36	36	0%	135
20	P _L	11	11	1%	135
	P _L + P _B	19	20	3%	135
21	P _L	42	42	1%	135
	P _L + P _B	121	122	1%	135
22	P _M	50	50	0%	90
	P _M + P _B	97	97	0%	135
	P _M + P _B + Q + F	377	382	1%	<i>Fatigue (see below)</i>
23	P _M	31	32	3%	90
	P _M + P _B	92	91	-1%	135
24	P _M	29	30	5%	90
	P _M + P _B	94	94	0%	135
25	P _M	60	64	6%	90
	P _M + P _B	127	131	3%	135
26	P _M + P _B + Q + F	141	144	2%	<i>Fatigue (see below)</i>
27	P _M + P _B + Q + F	29	32	10%	<i>Fatigue (see below)</i>
28	P _M + P _B + Q + F	144	155	8%	<i>Fatigue (see below)</i>
29	P _M + P _B + Q + F	49	54	10%	<i>Fatigue (see below)</i>
30	P _L	4	4	5%	135
	P _L + P _B	13	13	3%	135
31	P _L	8	8	-4%	135
	P _L + P _B	11	11	-2%	135

**Rotor Spider Fatigue Damage Resistance**

The Fatigue Cumulative Damage results from TABLE XII of the Rotor Spider Finite Element Analysis report *H-822600 MKB 24-201 F ED-01rev1* are compared to the Fatigue Cumulative Damage from the Start-Stop cycles with an additional 60MW. The same numerical model is used to update the Fatigue Cumulative Damage calculations

Runaway event fatigue cycles were also evaluated into the initial rotor spider FEA and negligible damage was calculated following the ASME approach. Thus, total cumulative damage is fully driven by the start-stop cycles damage and the runaway event fatigue cycles can be neglected

The results are discussed in section 4.1

NOMINAL OPERATION 448.5 MVA / 403.65 MW		22	26	27	28	29
Start-Stop Cycles	Stress Amplitude , Sa	63	100	132	131	See NOTE 1 below
	Allowable Number of Cycles , N	4.73 $\times 10^8$	377 920	104 630	108 240	

NOMINAL OPERATION 515.2 MVA / 463.65 MW		22	26	27	28	29
Start-Stop Cycles	Stress Amplitude , Sa	76	104	145	141	See NOTE 1 below
	Allowable Number of Cycles , N	1.20 $\times 10^7$	329 727	72 394	81 002	

***NOTE 1**

Close review of the Finite Element Analysis revealed that a Region Of Interest at the bottom of the wedge carrier located on the opposite side of ROI #29 in the FEA report H-822600 MKB 24-201 F ED-01rev1 has been omitted during the initial analysis. This discovery led to review the past fatigue assessment to evaluate if Helms rotor spider is at risk of fatigue issue.

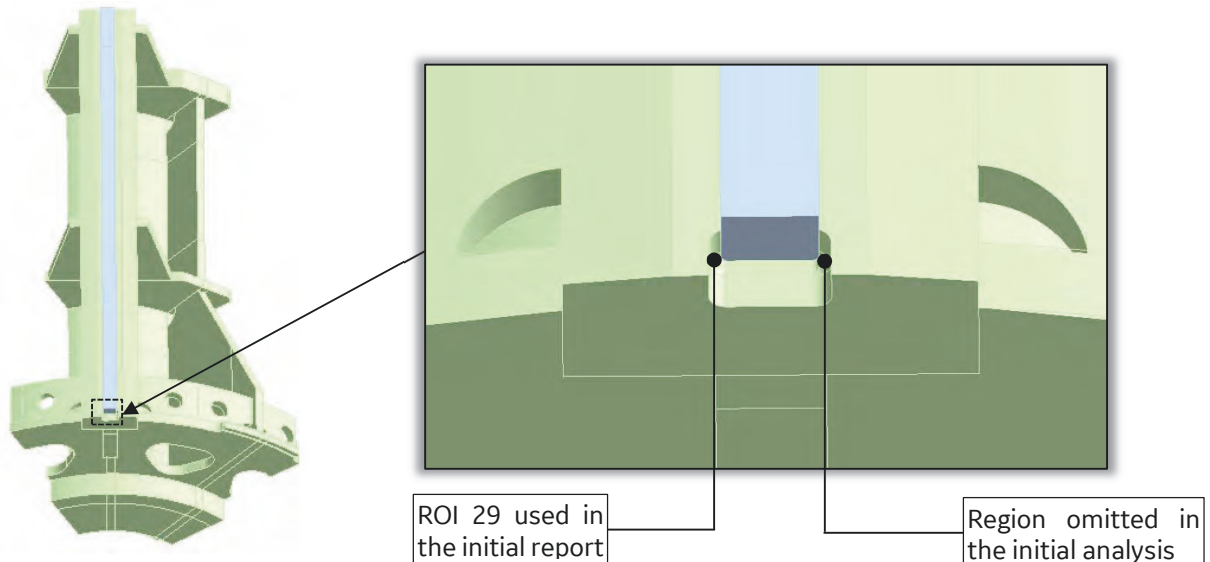


Figure 4 Rotor Spider FEA omitted Region of Interest

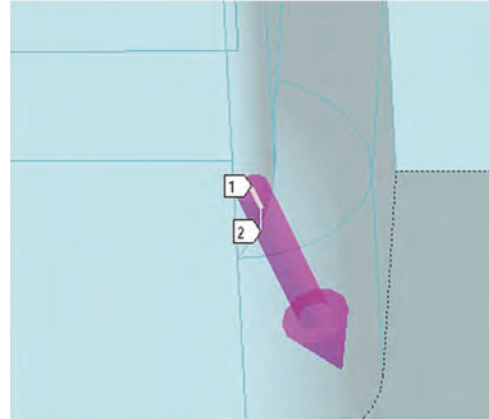
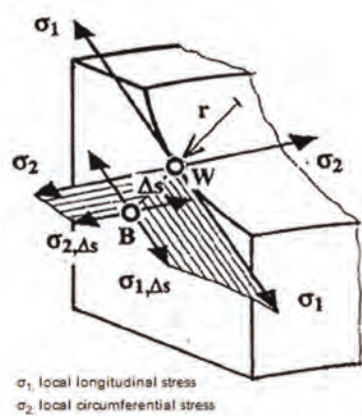
The results of the fatigue assessment, in accordance with ASME B&PV Code Section VIII, Division 2 chapter 5.5.3 fatigue assessment methodology for carbon steel components, showed that a very small area at the bottom of the wedge carrier does not respect the ASME criteria defined in the initial technical specification which was three start-stops per day for 50 years.

It should be noted that the Region of Interest is located very close to a convergence of numerical singularities and that the latter could have non-physical detrimental effects around this ROI.

ASME B&PV Code Section VIII, Division 2 chapter 5.5.3 fatigue assessment methodology for carbon steel components relies only on the von-Mises stress amplitude (S_a) calculated at given location using S-N curves 3.F.1 and 3.F.2. Numerous safety factors are imbedded into those curves (combined safety factor of 20 on the allowable cycles and 2 on the allowable stress amplitude), including one for the mean stress effect on the fatigue resistance regardless to the specific one calculated for a given fatigue cycles investigated. Also, principal stresses are not considered to evaluate if the given ROI is affected by tension or compression stresses, which influence the fatigue resistance.

It means that for some cases, ASME can be very conservative if the real fatigue resistance is underestimated as beneficial contributors are not considered into the fatigue assessment. Alternative methodology, such as FKM Guideline 6th Edition, Chapter 4 (widely used in Europe), considers mean stress and principal stresses to more effectively evaluate the fatigue resistance of a given ROI.

Following the FKM methodology, mean stresses and stress amplitudes are extracted at the ROI, called reference point (W on the upper diagram and pt 1 on the FEM) and underneath the surface (B and pt 2) at distance Δs following normal orientation (r).



The mean and amplitude stresses at reference point 1 calculated in ANSYS using local coordinate system are shown below.

Amplitude Stresses	$\sigma_{1,a}$	216.9	MPa
	$\sigma_{2,a}$	48.3	MPa
	$\sigma_{3,a}$	3.7	MPa
Mean Stresses	$\sigma_{1,m}$	-1.0	MPa
	$\sigma_{2,m}$	17.4	MPa
	$\sigma_{3,m}$	0.5	MPa

Amplitude stresses at point 2 with a distance Δ of 2mm below the reference point:

Amplitude Stresses	$\sigma_{1\Delta,a}$	130.9	MPa
	$\sigma_{2\Delta,a}$	40.7	MPa
	$\sigma_{3\Delta,a}$	38.3	MPa

The following table shows the start-stop cycles Fatigue Damage calculated with FKM Guideline Methodology.

FKM allowable start-stop cycles	Start-Stop Cycles 448.5 MVA 403.65 MW	Start-Stop Cycles 515.2 MVA 463.65 MW
	83 449	57 436



**APPENDIX B
ROTOR POLE END PLATE RESULTS COMPARISON**



Rotor Pole End Plate Points of Interests

As a reminder, Figure 2 extracted from the Rotor Pole End Plate Finite Element Analysis report *H-822600 MKB 26-200 F ED-02* shows the interest points where stresses are evaluated. The study will focus on Point 2 and 3 as they are assumed to be the most impacted by the torque increase from the 15% Power increase.

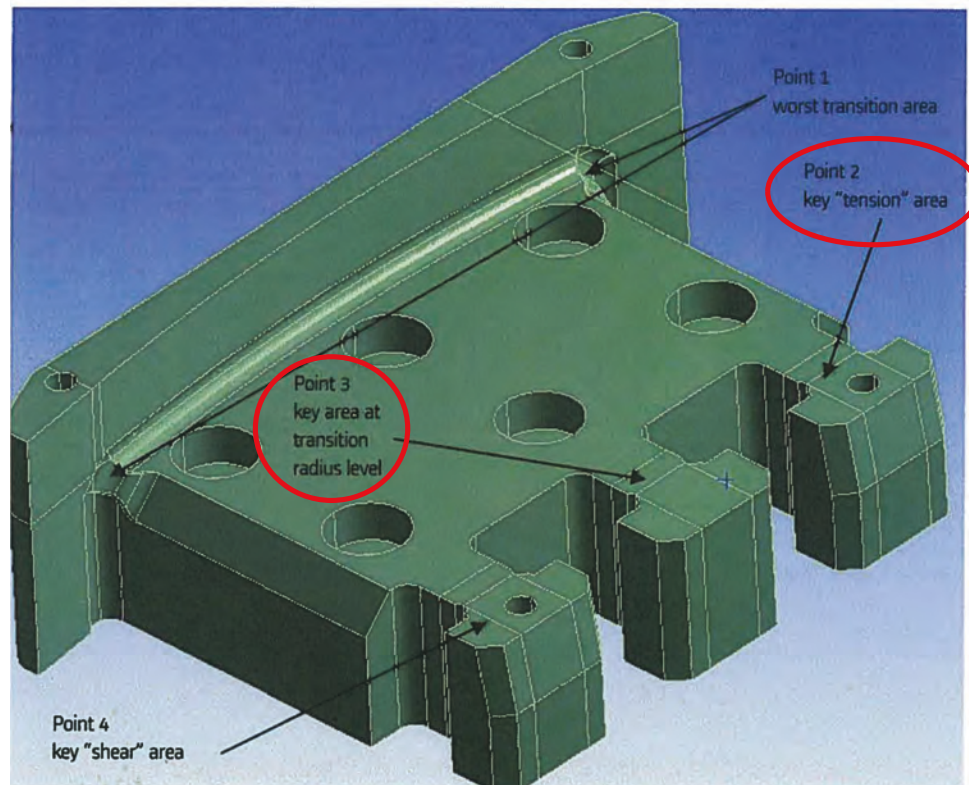


Figure 2 – Interest Point Locations



Rotor Pole End Plate Static Stress Comparison

The nominal operation static Von Mises stresses at Point Of Interest 2 and 3, from TABLE V of the Rotor Pole End Plate Finite Element Analysis report *H-822600 MKB 26-200 F ED-02*, are compared to the Von Mises static stresses from the nominal operation load case with an additional 60MW. The table below present the analytical calculation proposed to evaluate the impact of the torque increase.

The results are discussed in section 4.2.

	Normal Operation	Maximum Overspeed	
	360	540	RPM
	37.70	56.55	Rad/s
POINT 2			
P_m , General Membrane Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	82	182	MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	104.0	228	MPa
Estimation of the stress from the torque <u>only</u> @ 403.65 MW $104 - 228 * \frac{360^2}{540^2}$	2.7		MPa
Estimation of the stress increase due to the 15% power increase @ 463.65 MW, Power increase of 15% $2.7 * 0.15$	0.4		MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area @ 463.65 MW, assuming a power increase of 15% $104.0 + 0.4$	104.4		MPa
POINT 3			
P_m , General Membrane Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	92	203	MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	115	248	MPa
Estimation of the stress from the torque <u>only</u> @ 403.65 MW	4.8		MPa
Estimation of the stress increase due to the 15% power increase @ 463.65 MW, Power increase of 15%	0.7		MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area @ 463.65 MW, assuming a power increase of 15%	115.7		MPa



POINT 3			
P_m + P_b + Q + F , Stress In T-Tail Tension Area <i>From Report H-822600 MKB 26-200 F ED-02</i>	340		MPa
P_m + P_b + Q + F , Stress In T-Tail Tension Area @ 463.65 MW, assuming a power increase of 15% $115.7 * \frac{340}{115}$	342		MPa



APPENDIX C
ROTOR POLE LAMINATION RESULTS COMPARISON



Rotor Pole Lamination Points of Interests

As a reminder, Figure 2 extracted from the Rotor Pole Lamination Finite Element Analysis report *H-822600 MKB 26-200 F ED-02* shows the interest points where stresses are evaluated. The study will focus on Point 2 and 3 as they are assumed to be the most impacted by the torque increase from the 15% Power increase.

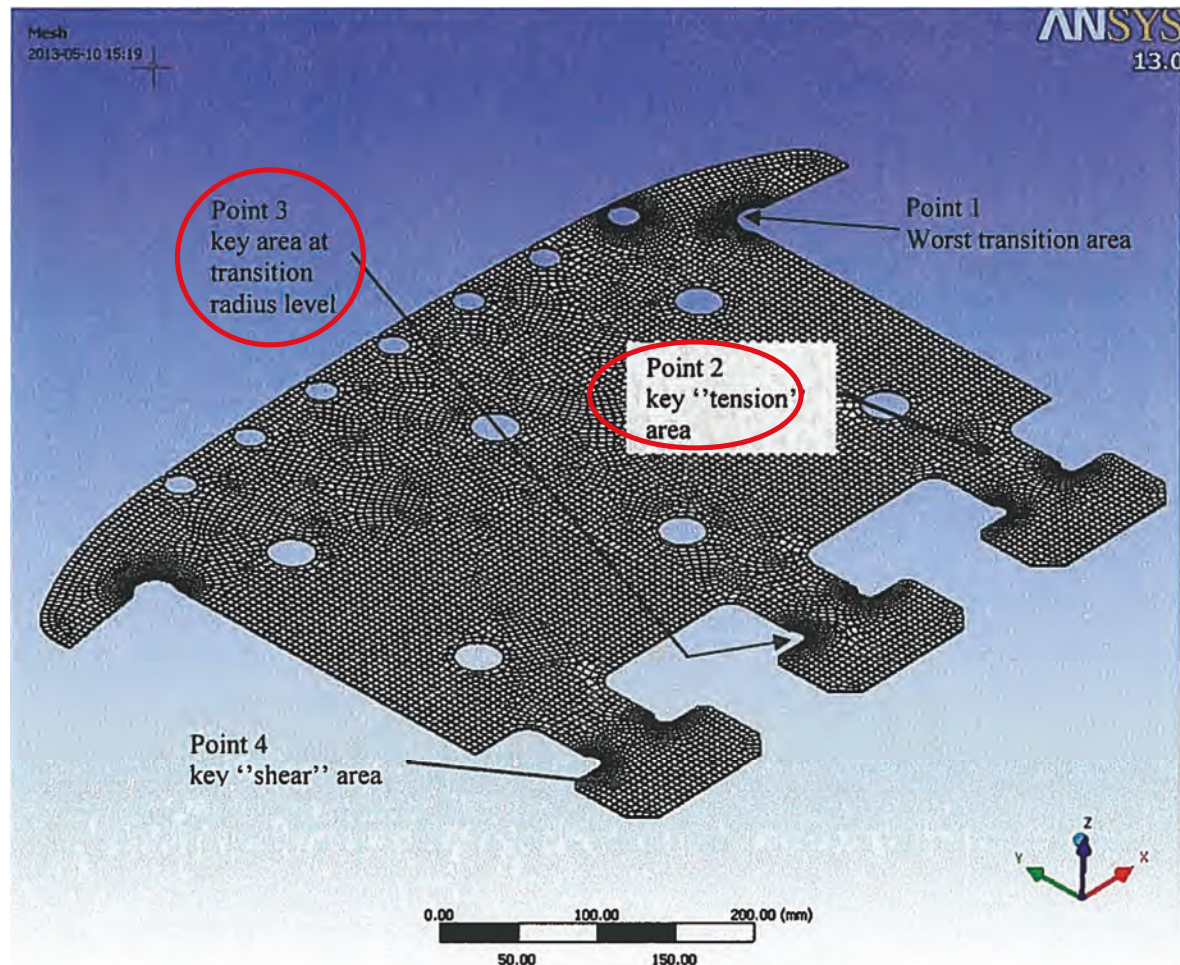


Figure 2 – Interest Point Locations

**Rotor Pole Lamination Static Stress Comparison**

The nominal operation static Von Mises stresses at Point Of Interest 2 and 3, from TABLE V of the Rotor Pole End Plate Finite Element Analysis report *H-822600 MKB 26-200 F ED-02*, are compared to the Von Mises static stresses from the nominal operation load case with an additional 60MW. The table below present the analytical calculation proposed to evaluate the impact of the torque increase (refer to the Appendix B for more details about the equations used).

The results are discussed in section 4.3.

	Normal Operation	Maximum Overspeed	
	360	540	RPM
	37.70	56.55	Rad/s
POINT 2			
P_m , General Membrane Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	54	116	MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	56	120	MPa
Estimation of the stress from the torque only @ 403.65 MW	2.7		MPa
Estimation of the stress increase due to the 15% power increase @ 463.65 MW, Power increase of 15%	0.4		MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area @ 463.65 MW, assuming a power increase of 15%	56.4		MPa
POINT 3			
P_m , General Membrane Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	62	132	MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area <i>From Report H-822600 MKB 26-200 F ED-02</i>	65	140	MPa
Estimation of the stress from the torque only @ 403.65 MW	2.8		MPa
Estimation of the stress increase due to the 15% power increase @ 463.65 MW, Power increase of 15%	0.5		MPa
P_m + P_b , General Membrane Stress + Primary Bending Stress in T-Tail tension area @ 463.65 MW, assuming a power increase of 15%	65.4		MPa
P_m + P_b + Q + F , Stress In T-Tail Tension Area <i>From Report H-822600 MKB 26-200 F ED-02</i>	233		MPa
P_m + P_b + Q + F , Stress In T-Tail Tension Area @ 463.65 MW, assuming a power increase of 15%	234		MPa

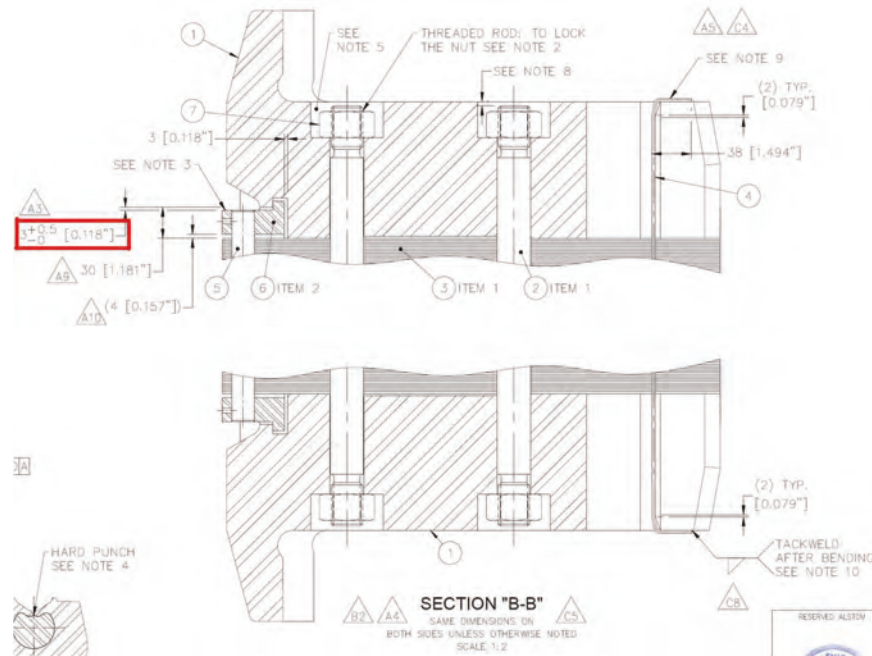


APPENDIX D
ROTOR POLE DAMPER BAR THERMAL EXPANSION CALCULATIONS



The maximum allowable thermal expansion is calculated using the clearance shown in drawing H-822600 MKB 26-201 F TL_01revD.

The results are discussed in section 4.4.



Damper Bar Length	2562	mm
Damper Bar Top Clearance <i>Between tip and bottom surface of End Plate</i>	3	mm
Coefficient of thermal Expansion <i>Assuming General Copper material</i>	1.64×10^{-5}	$^{\circ}\text{C}^{-1}$
Max Thermal Expansion Allowable <i>2X Clearance</i>	6	mm
Max Temperature Gradient Based on max clearance	142.8	$^{\circ}\text{C}$



**APPENDIX E
ROTOR RIM RESULTS COMPARISON**



Rotor Rim Static Stress Comparison

The nominal operation static stresses from Section 7.4 (extract below) of the Rotor Rim Calculations report *H-822600 MKB 25-001 F ED-01*, are compared to the static stresses calculated with an additional 60MW. The table below present the analytical calculation proposed to evaluate the impact of the torque increase rim key area.

The results are discussed in section 4.5.

Extract From Report *H-822600 MKB 25-001 F ED-01*

7.4 RESULTS

		Calculated stress (value)	Calculated stress (% yield point)	Design criteria
$\sigma_{MT, tole}$	Compressive stress on the rim lamination by tangential force	202 Mpa [29.3 ksi]	29 % LE_j	< 50 % LE_j
$\sigma_{MT, wedge}$	Compressive stress on the wedge carrier by tangential force	66 Mpa [9.57 ksi]	22 % LE_w	< 50 % LE_w
τ_{cle}	Maximum shear stress in the rim key by tangential force	70 Mpa [10.2 ksi]	10 % LE_{RK}	< 19 % LE_{RK}
$\sigma_{F, cle}$	Maximum flexural stress in the rim key by tangential force	69 Mpa [10 ksi]	10 % LE_{RK}	< 33 % LE_{RK}

Static stresses updated with an additional 60 MW

		Calculated Stress (value)	Calculated stress (% yield point)	Design Criteria
$\sigma_{MT, tole}$	Compressive stress on the rim lamination by tangential force	229 Mpa [33.2 ksi]	33% LE_j	<50% LE_j
$\sigma_{MT, wedge}$	Compressive stress on the wedge carrier by tangential force	74 Mpa [10.8 ksi]	25% LE_w	<50% LE_w
τ_{cle}	Maximum shear stress in the rim key by tangential force	79 Mpa [11.5 ksi]	11% LE_{RK}	<19% LE_{RK}
$\sigma_{F, cle}$	Maximum flexural stress in the rim key by tangential force	63 Mpa [9.2 ksi]	9% LE_{RK}	<33% LE_{RK}



APPENDIX F
GENERATOR SHAFT TORSIONAL STRESS RESULTS COMPARISON



Torsional stresses are analytically calculated for the original power and the increased power is then compared to a criterion recognized in shaft design for hydroelectric units.

- $T_{\text{Shaft Allowable}} = 41 \text{ MPa}$

The results are discussed in section 4.6.

	448.5 MVA 403.65 MW	515.2 MVA 463.65 MW	
Generator Output	448.50	515.17	MVA
Power factor	0.90	0.90	
Nominal Power	403.65	463.65	MW
Nominal Speed	360	360	RPM
Nominal Speed	37.70	37.70	rad/s
Nominal Torque	10 707 149	12 298 698	N*m
Generator Shaft OD	1 067		mm
Generator Shaft ID	261		mm
Polar moment of Inertia, J	1.27×10^{11}		mm ⁴
τ_{Torsion} (Generator Shaft)	45.1	51.7	Mpa



**APPENDIX G
ROTOR LOWER COUPLING ECCENTRIC SLEEVE BEARING STRESS
RESULTS COMPARISON**



The rotor lower coupling eccentric sleeve bearing stress calculations are presented in section 5.2 (Extract Below) of the Lower Rotor Coupling Calculation Report *H-822600 MKB 23-011 F ED-01* are compared to the bearing stresses calculated with an additional 60MW.

The results are discussed in section 4.7.

Extract From Report *H-822600 MKB 23-011 F ED-01*

5.2 MAXIMUM TORQUE ECCENTRIC SLEEVE BEARING STRESS

Data :

Number of sleeves	= 20	
Flange pitch diameter	= 1816.1 mm	[71.5"]
Inside diameter of the new eccentric sleeves	= 107.8 mm	[4.245"]
Protrusion of the existing shear sleeves	= 38.57 mm	[1.519"]
Chamfer height on existing shear sleeves	= 5 mm	[0.197"]
Chamfer height on new eccentric sleeves	= 15 mm	[0.591"]
Material yield strength	= 248 MPa	[36 ksi]

Calculation :

Load per sleeve	= 2.95E6 N	[663 186 lbf]
Effective height of contact surface	= 18.57 mm	[0.731"]
Bearing stress	= 73.6 MPa	[10.7 ksi]
Maximum acceptable	= 147 MPa	[21.2 ksi]
(ALSTOM standard:	= 2/3 * yield)	

Under the new operating condition from a 15% power increase, the load per sleeve is increased to 3.36×10^6 N. Under the torque resulting from an additional 60MW, the bearing stresses in the rotor lower coupling eccentric sleeve is **84.6 MPa**.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT E
BLACK AND VEATCH FEASIBILITY STUDY

HELMS UPRATE STUDY

B&V PROJECT NO. 408477



PREPARED FOR

Pacific Gas and Electric Company

24 AUGUST 2021



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Executive Summary

Pacific Gas and Electric Company (PG&E) has requested Black & Veatch to investigate the potential for increasing the overall output power at Helms Pump Storage Plant (Helms) which has an existing capacity of 1,212 MW when all three units are operating at their maximum output of 404 MW each. Helms is in the early stage of relicensing and if it is discovered that there is additional hydraulic capacity in the existing conveyance system, PG&E is interested in investigating the possibility of increasing the capacity of the powerhouse. This report includes a high-level study of the options available to increase generation capacity at Helms that could be subsequently used as justification for additional engineering required to further refine the technical and economic feasibility of a possible Helms capacity increase.

The first task of the study was to perform a hydraulic analysis to determine the maximum potential hydraulic flow through the existing conveyance system using typical velocity constraints in the tunnel and penstock sections. The results of the hydraulic analysis show that there is approximately 400 MW of additional hydraulic capacity available in the existing system.

Based on the results of the hydraulic analysis, Black & Veatch focused the study around the three main alternatives listed below. Costs developed are for full engineering, procurement, and construction and include indirect costs associated with contractor general conditions, contractor overhead and profit, startup and commissioning, insurance, and tax but do not include PG&E labor costs or permitting costs. Cost also do not include any required modifications to substations or transmission lines required to transmit the additional energy generated. They also do not include costs for potential modifications to the existing surge chambers which may be required due to the increase in flow through the tunnels. As the alternatives are further developed with additional design, those costs will be added and cost estimate ranges will be reduced.

ALTERNATIVE 1: UPRATE THE EXISTING UNITS TO 460 MW EACH – NEW TOTAL PLANT CAPACITY OF 1,377 MW

The main features of this alternative include:

- Rewind Units 1 and 3 similar to the recently rewound Unit 2.
- Install new runners for all three units that are optimized for higher flow and lower head.
- Uprate or replace existing balance of plant electrical equipment to operate at the higher unit outputs.

The Parametric Cost Estimate range for this alternative is \$263M - \$493M resulting in an installed cost/kW range of \$1,594 - \$2,988.

ALTERNATIVE 2: INSTALL A NEW, FIXED SPEED 400 MW UNIT 4 – NEW TOTAL PLANT CAPACITY OF 1,550MW

The main features of this alternative include:

- Expansion of the existing powerhouse cavern to the west.
- Installation of a new 400 MW fixed speed unit.
- Installation of new balance of plant electrical and mechanical equipment.

- Installation of new penstock and discharge tunnel and connect them to the existing main intake and discharge tunnels.
- Reduction in capacity at the new maximum flow for the existing units is 40 MW due to head loss caused by the increased flow.

The Parametric Cost Estimate range for this alternative is \$292 - 548M resulting in an installed cost/kW range of \$730 - \$1,370.

Sub alternatives include:

- Utilizing a variable speed configuration which would increase the estimated costs by approximately 20%
- Installing a pump-turbine unit that is smaller than 400 MW. Cost estimates for a selection of smaller pump-turbine units are included in Section 7.

ALTERNATIVE 3: UPRATE THE EXISTING UNITS AND INSTALL A NEW, FIXED SPEED 400 MW UNIT 4 – NEW TOTAL PLANT CAPACITY OF 1,632 MW

The main features of this alternative include:

- Up-rate of the existing units as described in Alternative 1.
- Install a new 400 MW, fixed speed unit as described in Alternative 2.

The Parametric Cost Estimate range for this alternative is \$555-1,041M resulting in an installed cost/kW range of \$1,321-2,479.

RECOMMENDED NEXT STEPS

Based on the results of the hydraulic study and the cost estimates developed, it appears that adding additional generation at Helms is viable. Considering that the dams and water conveyance systems are already existing, utilizing the available hydraulic capacity to produce additional pump storage generation would result in one of the most cost-effective pumps storage projects currently in development. Expanding the existing facility also greatly reduces permitting risks and complexity compared to a new, green field pump storage project. If PG&E wishes to continue investigating the potential for increasing the generation output at Helms, the following next steps are recommended:

Regulatory

- Include proposed uprate/capacity addition in upcoming FERC re-licensing.
- Work with CAISO and CPUC to show a commercial need and estimated cost for future planning studies.

Transmission

- Explore options for interconnection and transmission for the additional capacity at Helms.
- Conduct a transmission line and substation capacity study to determine scope of work required to upgrade the lines from their current rating of 1,520 MVA/1,368 MW summer normal total.

Hydraulics

- Conduct targeted CFD analyses of specific key locations which may potentially include: TSV through existing turbine inlet, tunnel and penstock bifurcations, bottom of incline shaft, and intake gates to confirm assumed velocity limitations are acceptable.
- Revise the existing transient analysis considering the increased flow and the new turbine selections to determine if the existing surge chambers would need to be modified.

Additional Studies/Preliminary Design

- If moving forward with uprating the existing three units, perform a detailed uprate study which will analyze the existing pump-turbine units in detail to determine the scope of work involved with the uprate including selection of the new runners optimized for the higher flow, lower head conditions.
- If moving forward with one of the Unit 4 concepts, select 1-2 alternatives to be refined through development of a 10% level design including OEM equipment selection and quotations. Consideration should be given to the optimal size of the new unit and whether variable speed technology will be utilized.

1.0 Need for Additional Pump Storage Capacity in California

The assessment on the need for additional pump storage capacity in California is based on publicly available documents produced by the California Public Utilities Commission (CPUC), California Independent System Operator (CAISO), California Energy Commission (CEC) and California Air Resources Board (CARB).

Planning studies for both near term (2030) and future (2045) scenarios all point to a need due to increased variable solar, wind, and offshore wind generation and the ability manage both the renewable resources and electricity demand with energy storage. A need to increase energy storage from both chemical and pumped hydro is described in each report to meet California's Senate Bill (SB) 100 Clean Energy goals. All goals are expected to be achievable by increasing pumped storage capacity.

1.1 CPUC INTEGRATED RESOURCE PLANNING MODEL FOR THE 2021-2022 TRANSMISSION PLANNING PROCESS

The 2021-2022 Integrated Resource Plan (IRP) included several detailed scenarios to aid in the CAISO's Transmission Planning Process (TPP). The base case portfolio that meets both policy and reliability purposes includes the goal of meeting a 46 million metric ton (MMT) greenhouse gas (GHG) emissions target in 2031 and includes pumped storage and additional out of state renewables. For the 2021-2022 IRP base case the policy and reliability case were combined into one base case portfolio.

In addition to the base case portfolio, two additional portfolios were included for a sensitivity analysis. One sensitivity portfolio meets a 38 MMT GHG emissions target by 2031 and the other sensitivity portfolio includes a large segment of offshore wind (OSW). In all three portfolios additional pumped storage capacity was identified as a needed resource as shown in Table 1-1.

Table 1-1 Pumped Storage Resources Identified in 2021-2022 IRP

	46 MMT PORTFOLIO (2031 RESULTS)	38 MMT PORTFOLIO (2031 RESULTS)	OSW PORTFOLIO (2031 RESULTS)
Pumped Storage Capacity Identified	627 MW	1,843 MW	1,613 MW

Many parties to the CPUC rulemaking argued that the 38 MMT GHG case should be considered the base case portfolio instead of a sensitivity portfolio. If the CPUC uses the 38 MMT portfolio as a base case, the need for new pumped storage capacity will likely further increase in future sensitivity scenarios.

As part of the 2021-2022 IRP portfolio planning process the CPUC performed a busbar mapping process to identify locations where identified generation resources could potentially interconnect with the grid. Three criteria were used to identify interconnection locations:

- Distance to transmission – includes the allowance for exceptions of lower voltages.
- Commercial Interest – includes consideration of projects in advanced stages of development identified through stakeholder comments.

- Consistency with prior years – focuses on reductions in selected resources assigned to a zone from the previous year’s mapping.

1.1.1 46 MMT Portfolio Busbar Mapping

In the 46 MMT scenario, the CPUC busbar mapping process identified two pumped storage hydro related substations for interconnection. The pumped storage hydro resources were mapped with 314 MW at the Sycamore Canyon Substation (likely the San Vicente Pumped Storage Project) and 313 MW mapped to Lee Lake substation (likely the Eagle Mountain Pumped Storage Project). This mapping reflected commercial interest and also was consistent with the 2020-2021 TPP 2019 RSP sensitivity portfolio. Commercial interest was determined on projects that have active or pending preliminary permits with the FERC and data on projects formally included in the CAISO interconnection queue.

1.1.2 38 MMT Busbar Mapping

In the 38 MMT scenario, the CPUC busbar mapping process resulted in the following distribution of pumped storage hydro: 500 MW at Lee Lake substation, 500 MW at Sycamore Canyon substation, and 843 MW at Red Bluff substation. Similar to the changes described for the 46 MMT base case, this adjustment better aligns pumped storage mapping with the 2020-2021 TPP portfolios and accounts for additional areas of commercial interest.

1.1.3 Offshore Wind Busbar Mapping

In the OSW scenario, the CPUC busbar mapping process resulted in the following distribution of pumped storage hydro: 500 MW at Lee Lake substation, 500 MW at Sycamore Canyon substation, and 495 MW at Red Bluff substation.

2.0 Hydraulic Study

The objective of the hydraulic study is to identify the potential for additional turbine generation capacity. The hydraulic analysis focused on identifying maximum turbine outputs associated with the hydraulic capacity of the existing Helms conveyance system including the tunnels, pipelines and penstocks. Specific unit selection and optimization of the pump-turbine equipment is outside the scope of work for this study and will be performed under a separate scope of work.

2.1 SYSTEM DESCRIPTION

The Helms Powerhouse is a 1,100-foot deep underground facility, built on the north side of Wishon Reservoir on the North Fork Kings River and located approximately 50 miles east of Fresno, California. Water is diverted from Courtright Reservoir (approximately three miles north of the powerhouse) and conveyed to the powerhouse through tunnels, a short aerial pipe and underground penstocks. The underground powerhouse discharges into a pressurized tailrace tunnel and into Wishon Reservoir (approximately one mile south of the powerhouse). Figure 2-1 presents a general profile of the Helms Pumped Storage Project.



Source: Pacific Gas and Electric Company [REDACTED]

Figure 2-1 Excerpt of Plan and Profile of Helms Pumped Storage Project

2.1.1 Pump-Turbine Units

The Helms Powerhouse is a pumped storage facility with a maximum generation capacity of 1,212 MW produced by three identical reversible Francis-type pump-turbine units. Each unit was originally rated at 480,000 horsepower (~350 MW) at a rated flow of 3,000 cfs and 1,625 feet of head. The maximum generation of 1,212 MW, 404 MW per unit, was set to 115% of the rated power.

Figure 2-2 presents the expected generation performance of the existing units as a function of the total plant output and available static head [REDACTED]



Source: Pacific Gas and Electric Company.

Figure 2-2 Expected Generation Per Total Plant Output and Static Head

As shown in Figure 2-2, the maximum plant output of 1,212 MW is expected to occur near maximum static head. For this reason, this hydraulic study considered conditions near maximum static head which corresponds with high water levels in Courtright Reservoir.

2.1.2 Conveyance System

Under generation/turbine operation, water is supplied to Helms Powerhouse from Courtright Reservoir through two 16,000-foot long tunnels, Tunnel 1 and Tunnel 2. These are predominantly [REDACTED]-foot diameter concrete lined tunnels. Tunnel 1 ends at the Lost Canyon Crossing (LCC), approximately 4,300 feet from the intake, where the water goes through a short section (205-foot long) of above ground 22-foot diameter welded steel pipe. A 600-foot tall surge chamber is located approximately 3,000 feet upstream of the start of the steel lined penstocks. Approximately 730 feet downstream of the surge chamber the tunnel slopes steeply downward to the powerhouse, where the tunnel splits into three identical steel lined penstocks, each penstock supplying one turbine unit. These penstocks are each [REDACTED] long, have an internal diameter ranging from [REDACTED] [REDACTED] and include stiffener rings. The penstocks terminate at the TSVs. Downstream of the units the water is conveyed through a [REDACTED] long tailrace tunnel (Tunnel 3) to Wishon Reservoir. The tailrace tunnel is mainly concrete lined, [REDACTED] diameter, and includes a 975-foot tall surge chamber located approximately 700 feet downstream of the Powerhouse. Under storage/pumped operation, water is conveyed in the

reverse direction from Wishon Reservoir to Courtright Reservoir, through the same units, operating in reverse rotation.

Figure 2-3 presents the general arrangement of the Helms Powerhouse penstocks and draft tube. Figure 2-4 presents the detailed profile of the steel liner penstocks 1, 2 and 3.



Source: Pacific Gas and Electric Company [REDACTED]

Figure 2-3 Excerpt of General Arrangement of Penstocks and Draft Tube Extensions



Source: Pacific Gas and Electric Company [REDACTED]

Figure 2-4 Excerpt of Profile of the Steel Lined Penstock

The water surface elevation (WSE) in Courtright Reservoir ranges from El. 8,184 (forebay maximum normal operation) to El. 8,020 (forebay minimum normal operation). The water surface elevation (WSE) in Wishon Reservoir ranges from El. 6550 (forebay maximum normal operation) to El. 6,440 (forebay minimum normal operation).

In the Powerhouse, the penstock centerline elevation is at El. 6,240 feet at the turbine inlet. At the turbine inlet the maximum upstream static head is 1,944 feet and the minimum downstream static head is 200 feet, resulting in a maximum differential static head of 1,744 feet.

Figure 2-5 presents the complete Hydraulic Grade Line (HGL) from Courtright Reservoir to Wishon Reservoir.

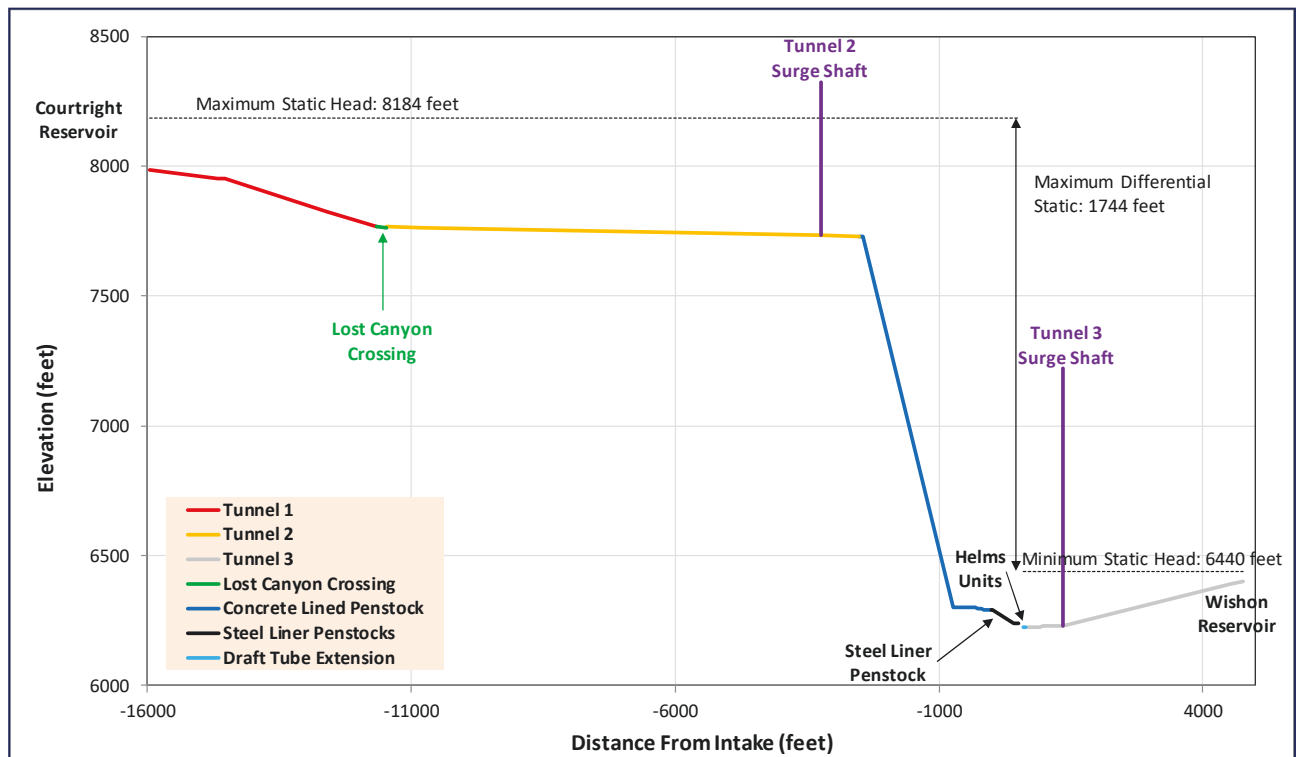


Figure 2-5 Longitudinal System Profile and Maximum Static HGL

2.2 HYDRAULIC MODEL

2.2.1 Existing Model

In 2018, Black & Veatch developed a hydraulic and transient model of Helms as part of PG&E's penstock transient program. The model was developed using Black & Veatch's in-house hydraulic modeling software, Pipit. Pipit is a software system used to conduct general hydraulic analyses and design of piping systems, with full transient computation capability.

The program allows modeling of detailed hydraulic components, including pipelines (tunnel or penstock), surge chambers, hydraulic control gates, and valves. Control procedures and equipment performance characteristics can also be programmed into the model. Modeling a Francis pump-turbine is not possible with the Pipit program; therefore, as a reasonable and affordable alternative, Black & Veatch used a simplified approach by modeling the wicket gates and turbines as valves.

This is a common modeling practice for the determination of the transient pressures in the upstream penstock, where flow-control through the unit is simulated using the wicket gates, and the turbine is treated as a variable headloss component.

2.2.2 Original Model Calibration

The 2018 hydraulic model was validated against multiple sets of field measured data to enhance the model accuracy. These included the following data sets:

- October 2008 index tests at Unit 3,
- January 2015 load rejection tests at Unit 2,
- May 2015 load rejection tests at Unit 3, and
- December 2015 load rejection tests at Unit 1.

The transient model was calibrated to match the valve operation and the pressure trace recorded during the load rejection tests. In the calibration exercise the operating parameters of the wicket gates (e.g., delay, closing speed, relative position, etc.) were input and checked against measured data to correlate upstream flow and pressure conditions against actual field results.

Figure 2-6 presents one of the model validations performed for the original model calibration, comparing surge HGL computed by the model to those recorded on the field.



Figure 2-6 Original Model Calibration Results at 100% Load at Unit 1

Although some separation between the test data and the model data can be seen, the two-time traces mimic one another very closely and a similarly close match was also obtained under various operating conditions. Overall, the results showed good calibration, therefore validating that the model accurately predicts conditions of flow and pressure.

2.2.3 2021 Model Update & Validity

For this uprate study the 2018 hydraulic model was revised to include refined estimates of the efficiency calculations during generation (turbine mode). These revisions were made by integrating the most recent testing data, including:

- 2018 index testing at Unit 1,
- 2020 index testing at Unit 2, and
- 2020 Unit 2 load rejection testing at Unit 2.

The 2020 test data were particularly useful since they were performed under conditions of near maximum head, with high water levels at Courtright Reservoir; therefore, allowing to better estimate of the maximum turbine output.

The 2018 and 2020 data sets were also used to verify the adequacy of the model estimate of headloss. The conditions of flow, pressure and generation (MW) recorded during these more recent tests did match relatively closely the conditions predicted by the model; as a result, modifying the model estimate of system headloss was not needed.

Additionally, two records including multi-unit operation were provided to evaluate the model accuracy in estimating headloss through the tunnels when all three units operate simultaneously (plant operation near 1,212 MW).

One partial record of three-unit operation at high output was provided. The data was recorded on [REDACTED] when three units operated simultaneously near 380 MW each (total plant output of 1138 MW). The data was limited to screen captures of monitoring screens, showing time traces of each unit MW output, flow and pressure, using plant instrumentation. Although the accuracy of the flow data can be questionable; the pressure plot shown on Figure 2-7 could be used to estimate the system headloss.



As shown in Figure 2-7, a pressure drop of approximately 130 feet can be identified between the static pressure of 1,840 feet at zero flow (Unit 2, blue trace time [REDACTED]) and the minimum pressure of 1,710 feet at maximum output (just after time [REDACTED]). When using the model to produce similar MW output under the same static conditions, the pressure drop estimated by the model was near 140 feet; therefore, very close to the observed conditions, yet slightly conservative.

Another three-unit operation at high load was recorded with instrumentation installed during the month of May 2021, reaching a maximum plant output stabilizing above 1,120 MW for approximately 20 minutes. Turbine output, flowrate, and penstock pressure (upstream of TSV) were recorded for each unit, along with the static conditions at Courtright Reservoir and Wishon reservoir. Figure 2-9 presents a plot of units 1, 2 and 3 penstock pressures and turbine output versus time, showing a maximum plant output near 1,120 MW (unit 1 at 380 MW, unit 2 at 365 MW and unit 3 at 375 MW) occurring around time [REDACTED]. At peak plant output the flow was estimated to be near 9,300 cfs (using the unit 1 flow to replace the inaccurate reading from the unit 3 flowmeter).



Figure 2-8 Unit 1, 2 and 3 Turbine Output (MW) and Penstock Pressures (psi) on [REDACTED]

As shown in Figure 2-9, a pressure drop of 54 psi (124 feet) was identified between the static pressure and the minimum penstock pressures at peak plant output of 1,120 MW. This data point is very close to the data point recorded in February 2020 (130 feet at 1,138 MW); therefore, increasing confidence in the measured data. When using the model to produce similar MW output under the same peak conditions recorded on the [REDACTED], the pressure drop estimated by the model was near 133 feet; therefore, very close to the observed conditions and still slightly conservative (+7%).

Following these tests at high plant output, Black & Veatch believes that the model provides the accuracy needed for this uprate study.

2.3 ANALYSIS APPROACH

The objective of the analysis was to identify the potential for increase in turbine MW output from a hydraulic standpoint, independent from potential optimization of the mechanical and/or electrical equipment. The approach used in this hydraulic analysis consisted in varying the hydraulic operating point of the turbine defined by the operating flow at the operating net head, while assuming a fixed system conveyance geometry, a constant turbine efficiency, and operation under the same conditions of near maximum water levels at Courtright Reservoir. The magnitude of the potential gain in turbine MW output could be estimated by comparing turbine MW output when operating at different operating points of flow and net head.

The approach simulated a turbine replacement in the model, which was achieved by modeling different pressure drop across the turbine component of the model (assuming full gate position, e.g. wicket gates 100% open). The steady state model simulation was used to determine flow, net head and MW output for each “turbine replacement”. Finally, this iterative approach allowed to determine the maximum turbine MW output. Figure 2-9 shows an illustration of a maximum output occurring at 462 MW when plotting turbine MW output versus penstock velocity, for the simulated alternatives of turbine replacement.



2.4 DESIGN CRITERIA ON MAXIMUM VELOCITY

As illustrated in Figure 2-9, model simulations with operation at very high velocity were performed in order to identify the maximum turbine output. However, operation at such high velocity may not be acceptable. The concerns associated with high velocity include erosion and vibration and unaccounted for excessive headloss.

For this purpose, preliminary design criteria were established to limit the analysis to considering realistic operation for the existing Helms tunnels, piping and penstocks. Black and Veatch performed a rapid review of similar high flow facilities and after a follow-up discussion with PG&E it was proposed to limit the maximum velocities to:

- 30 ft/sec inside the concrete lined tunnels, and
- 100 ft/sec inside the steel piping or steel lined penstocks.

It is estimated that under current operation the maximum velocity inside the existing turbine shut-off valve (TSV) and the turbine inlet piping (■■■■-ft diameter) may reach 65 to 75 ft/sec when generating at maximum unit output (404 MW), corresponding to a single unit operating at 3,500 cfs. Similarly, under current operation the maximum velocity inside the existing concrete lined tunnels (■■-ft diameter) may reach 10 to 20 ft/sec when generating at maximum plant output (1,212 MW), corresponding to a total plant flow of 10,000 cfs. Table 2-1 shows the correspondence between flow and velocity for the existing water conduits, ranging in size from ■■■-ft diameter

(concrete lined tunnel) to [REDACTED]-inch diameter (TSV and turbine inlet piping). Table 2-1 shows two conditions of operation for each conduit: single unit operation with flows ranging from 3,000 to 5,000 cfs, and three-unit operation with total plant flows ranging from 9,000 to 15,000 cfs.

Table 2-1 Corresponding Flow and Velocity Through Existing Water Conduits

2.5 MODEL RESULTS

The potential for additional turbine generation was evaluated for three alternatives. The first alternative considered an upgrade of the existing units, the second alternative considered the addition of a fourth unit, and the third alternative considered the combination of upgrading the existing units and adding a fourth unit. For each alternative the results are presented in a form of a graph showing the unit or plant MW output as a function of the controlling velocity.

2.5.1 Alternative 1 - Upgrade of Existing Units

The hydraulic model was used to simulate a replacement of the existing pump-turbines with larger units. As shown in Figure 2-10, the turbine output may reach a maximum of 459 MW without exceeding the maximum velocity criteria.

This potential increase of 55 MW per unit assumes simultaneous operation of three identical pump-turbines (1,377 MW total plant output), each upgraded to operate at the rated condition of 4,870 cfs @ 1210-ft net head, with a turbine efficiency of 92%, the existing conveyance geometry remains

unchanged and operation near maximum water levels at Courtright Reservoir. This operation would produce the maximum velocity of 100 ft/sec inside the [REDACTED] inch diameter TSV and turbine inlet piping, and a velocity of 26 ft/sec inside the [REDACTED] ft and 22-ft diameter concrete lined tunnels.



Figure 2-10 Maximum Turbine MW Output with Upgrade of the Existing Units

2.5.2 Alternative 2 - Addition of a Fourth Unit

For the analysis of the operation with an additional fourth unit, the model was updated to include a new parallel water conveyance. This conveyance would tie-in to the [REDACTED]-ft diameter tunnel, pass through the existing plug, and terminate at a tie-in to the [REDACTED]-ft diameter tailrace tunnel, just upstream of the tailrace rock trap. For simplification, the new conduit diameters were assumed identical to those of the existing conduits ([REDACTED] ft diameter concrete lined upstream and downstream tunnels, [REDACTED]-ft and [REDACTED]-ft diameter penstocks, and [REDACTED]-inch / [REDACTED]-ft diameter TSV and turbine inlet piping). Figure 2-11 presents a schematic layout of the proposed additional conveyance, shown in red lines.



Figure 2-11 Proposed Additional Conveyance to Fourth Unit

The model simulated operation of a fourth pump-turbine unit, simultaneously with the existing pump-turbine units. In this configuration, it was identified that a new unit of up to 440 MW could be added. However, when operating all four units simultaneously, the existing units will experience a reduction of their maximum output, from 404 MW to 370 MW. This reduction is due to the increase of the total plant flow, causing a reduction of the net head at the inlet of the unchanged existing turbines. Despite this reduction, the total plant maximum output would increase 340 MW to 1,550 MW (from the current 1,212 MW).

As shown in Figure 2-12, the maximum plant output of 1,550 MW would occur with a maximum flow velocity of 100 ft/sec at the new turbine inlet (assumed to be [REDACTED]-ft diameter, same as existing). This assumed the simultaneous operation of all four units, with the new turbine operating at the rated condition of 4,870 cfs @ 1170-ft net head, with a turbine efficiency of 92%, the existing conveyance geometry remains unchanged, and operation near maximum water levels at Courtright Reservoir. This operation would produce the maximum velocity of 100 ft/sec inside the new [REDACTED]-inch diameter TSV and turbine inlet piping, and a velocity of 26 ft/sec inside the [REDACTED]-ft concrete lined tunnels.



Figure 2-12 Maximum Plant MW Output with the Addition of a Fourth Unit

PG&E also expressed interest in the fourth unit being smaller than the existing units to add operational flexibility for generation at lower outputs, near 100 or 200 MW. It should be noted that when considering a smaller fourth unit (100 to 200 MW), the negative impact on the unchanged existing units will also be smaller, when operating all four units at maximum output. This is because the smaller fourth unit requires a smaller increase of the total plant flow, and as consequence it has a smaller impact on the net head, as listed below:

- 10 MW reduction at the existing units, with the addition of a 110 MW fourth unit.
- 20 MW reduction at the existing units, with the addition of a 215 MW fourth unit.
- 25 MW reduction at the existing units, with the addition of a 300 MW fourth unit.
- 34 MW reduction at the existing units, with the addition of a 440 MW fourth unit.

Finally, PG&E expressed interest in identifying a solution with a very large fourth unit to maximize the utilization of the available power without uprating the existing units. Advantages to this approach include maximizing the gains against the flat costs associated with installing a fourth unit regardless of its size, making up more of the lost power when one unit is in outage (valid for all three unit annual dual outages, e.g. six outages of one to two week duration each), and when the new unit is offline the other units still have the same power as they always had.

The model was used to determine a potential maximum size for a fourth unit. The larger the fourth water path the larger the potential turbine; however, the limiting parameter is eventually the maximum speed of 30 ft/sec allowed through the existing long 100-ft diameter tunnels. A potential for an 820 MW fourth unit was identified, for a total plant output of 1,870 MW, when operating simultaneously with the three existing unchanged units and water path (operating at 350 MW each at maximum plant output). This alternative assumed a significant upsizing of the fourth water path (100-ft diameter tunnel, 100 and 100-ft diameter penstocks and 100-ft diameter TSV and turbine inlet) for the velocities through the fourth water path to match those through the existing unit penstocks and tunnels, while reaching the maximum allowable velocity of 30 ft/sec through the 100-diameter tunnels. Currently, the largest installed pump-turbine in the world is 500 MW. Although larger units are technically feasible, this would be a very large increase in size and there would be risks associated with a first of its kind unit of that size and complexity.

2.5.3 Alternative 3 - Combination of Existing Units Upgrade and Fourth Unit Addition

For the analysis of this alternative, the model assumed the four conveyance geometries were identical and matching the existing; however, all pump-turbines (four of them) were modified and assumed identical.

As shown in Figure 2-13, it was identified that each turbine output may reach a maximum of 408 MW (reduced from 413 MW due to high velocity conditions in the tunnels), resulting in a total plant maximum output of 1,632 MW.

This potential increase of 420 MW, from the current 1,212 MW to the estimated 1,632 MW, assumed the simultaneous operation of four new identical pump-turbines, operating at the rated condition of 4,290 cfs at 1220-ft net head, with a turbine efficiency of 92%, assuming the existing conveyance geometry remained unchanged and an operation near maximum water levels at Courtright Reservoir. This operation would produce the maximum velocity of 30 ft/sec inside the existing 100-ft diameter tunnels and a velocity of 88 ft/sec inside the existing TSV and turbine inlet piping.



Figure 2-13 Maximum Turbine MW Output with Four Identical New Units

PG&E inquired about reducing the system headloss by improving the hydraulics of the trifurcation, bifurcations, or even enlarging the existing penstocks. However, the model showed that most of the system headloss is produced by friction over the long length of the 10-ft diameter tunnels (approximately 3 miles long). The next highest headloss occurs at the Lost Canyon Crossing (conveying the total plant flow through a reduced diameter, 10-ft diameter steel pipe), rather than through the powerhouse. It was estimated that the maximum headloss recovery may reach 20 feet (10 feet by improving the trifurcation and bifurcations + 10 feet by replacing the penstocks); however, this would only represent a 1.5% increase in power generation at peak output and 0% at loads below 75%. For these reasons, and at this stage of the study, it does not appear justified to upsize the existing trifurcation, bifurcations or penstocks.

2.6 SUMMARY OF HYDRAULIC RESULTS

As a conclusion, it was identified that additional generation was available, with a potential for total plant output increase ranging from 165 MW (with the upgrade of the existing units) to 420 MW (with the addition of a fourth unit and the upgrade of the three existing units). These potential gains were identified without the need for enlargement of the long conveyance tunnels. Table 2-2 presents a summary of the hydraulic analyses and a comparison between the existing conditions and the three upgrade alternatives.

Table 2-2 Corresponding Flow and Velocity through Existing Water Conduits

ALTERNATIVE	MAXIMUM TOTAL PLANT OUTPUT (MW)	INCREASE FROM CURRENT MAXIMUM PLANT OUTPUT (MW)	UNIT OUTPUT AT MAXIMUM PLANT OUTPUT (MW)	HYDRAULIC LIMITATION
Do Nothing	1,212 MW	-	3 @ 404 MW	-
Upgrade Existing Units	1,377 MW	165 MW	3 @ 459 MW	100 ft/sec (Penstock)
Add Fourth Unit	1,550 MW	338 MW	3 @ 370 MW +1 @ 440 MW	100 ft/sec (Penstock) ¹
Add Fourth Unit and Upgrade Existing Units	1,632 MW	420 MW	4 @ 408 MW	30 ft/sec (Tunnels)
Note 1: Assuming new fourth conveyance with same conduit diameters as existing.				

3.0 Alternatives for Adding Additional General to Helms

Based on the results of the Hydraulic Study and discussions with PG&E, Black & Veatch has identified three alternatives for adding additional generation to the Helms Powerhouse. Each of the three alternatives are described at a high level along with a list of their pros and cons (Table 3-1 through Table 3-3). More detailed discussions of the alternatives are provided in later sections of this study and include variations to the alternatives including different unit sizes and the potential for utilizing variable speed equipment.

3.1 ALTERNATIVE 1 - UPRATE THE EXISTING UNITS TO 460 MW EACH

This alternative consists of uprating the existing three units at Helms to a rating of approximately 460 MW each. The work would include rewinding Units 1 and 3 similar to the recently rewound Unit 2. Additionally, all three units would require new runners which have been optimized to operate at higher flows and lower heads than the existing equipment. Modifications to the wicket gates and stay vanes may also be required. Finally, many of the balance of plant electrical components will need to be replaced or upgraded for the additional load from the units. The scope of work for this alternative is discussed in greater detail in Section 4.0.

Table 3-1 Pros and Cons for Uprating Existing Units

PROS	CONS
Lowest cost option.	No increase in operational flexibility.
Allows for phased approach to uprate.	Minimum load of plant may increase further reducing ability to meet lower load demands.
Shortest construction schedule.	Unit outages required to rewind units, install new runners, and upgrade/replace existing BoP electrical equipment.
No three-unit outage required.	
Minimal permitting required.	
Minimal geotechnical risk.	

3.2 ALTERNATIVE 2 - INSTALL A NEW UNIT 4

This alternative consists of expanding the existing powerhouse cavern to the West and installing a new Unit 4. Tunneling for a new penstock and discharge tunnel for the unit will be required. The new penstock and discharge tunnel will be connected to the existing main intake and discharge tunnels which will require a three-unit outage to make the connections. New balance of plant electrical equipment will need to be installed, including a variable speed drive if the additional flexibility provided by using that technology is deemed beneficial. Finally, the existing powerhouse crane would be extended to be able to service this new unit or a new, dedicated crane would be installed. The scope of work for this alternative is discussed in greater detail in Section 5.0 of this study and alternative technologies, including the use of variable speed drives are discussed in greater detail in Section 6.0.

Table 3-2 Pros and Cons for Installing a New Unit 4

PROS	CONS
Increased ability to meet load demands when one of the existing units are down.	Difficult and costly expansion of cavern and tunneling for intake/discharge conveyance.
Increased operational flexibility at lower plant outputs with variable speed unit.	Slightly reduced output of existing units depending on size of new Unit 4.
Upgrades/replacement of existing BoP electrical equipment not required.	Longest construction period.
No modifications to existing runners or generators required.	Three-unit outage required to make connection to main intake and discharge tunnels.

3.3 ALTERNATIVE 3 - UPRATE THE EXISTING UNITS AND INSTALL A NEW UNIT 4

This alternative is a combination of both alternatives described above. The existing units would be uprated and a new Unit 4 would also be installed.

Table 3-3 Pros and Cons for Uprating Existing Units and Installing a New Unit 4

PROS	CONS
Largest capacity increase	Highest cost option
Increased operational flexibility at lower plant outputs with variable speed Unit 4.	New runners, optimized for higher flow and lower head, will need to be installed.
Increased ability to meet load demands when one of the existing units are down.	Will require upgrade/replacement of existing BoP electrical equipment.
Allows for phased approach to uprate of existing units.	Difficult and costly expansion of cavern and tunneling for intake/discharge conveyance.
	Three-unit outage required to make connection to main intake and discharge tunnels.

4.0 Scope of Work for Potential Upgrades to Existing Units

This section describes the electrical scope of work required to upgrade the three existing units at Helms to up to 465 MW/516MVA each. This represents approximately a 15% increase from the existing operating limit. The upgrade would require Units 1 and 3 to be rewound similar to Unit 2. Additionally, all three existing units would require new runners that are optimized for higher flow and lower head conditions. Analysis of the existing generators and runners were outside of the scope of this evaluation but should be studied in detail if this upgrade alternative is selected for further consideration. Table 4-1 shows the existing electrical components included in the evaluation:

Table 4-1 Summary of Existing Electrical Equipment

DEVICE	MVA RATING OF EXISTING EQUIPMENT*	ADDITIONAL CAPACITY REQUIRED
Generator	448.5 MVA	68 MVA
5-Pole Switch	467 MVA	59 MVA
ISO-Phase Bus	448 MVA	68 MVA
GSU Transformers	450 MVA	66 MVA
230 kV Cable and Potheads	458 MVA	58 MVA
Transmission Line (Summer Normal)	1520 MVA (506 MVA/Unit)	30 MVA
Excitation System	499 MVA (Extrapolated)	17 MVA

*See Appendix A for references on where this data was obtained.

Based on the existing ratings, most of the main power components were sized with little margin beyond current operating conditions and the rating of the existing Generator Step-Up (GSU) transformers. Any significant upgrade to the existing generators is will require replacement or upgrade of these components.

4.1 ISO-PHASE BUS AND 5-POLE SWITCH

The ISO-Phase bus and 5-pole switches have similar ratings and are closely connected. Budgetary pricing was provided by Crown Electric for evaluation of air coolers and of complete replacement. Pricing includes installation except for field wiring.

1. Bus Cooling Evaluation – \$26,000
2. Addition of Air Coolers – \$900,000 - \$1,100,000 per unit
3. Full Bus Replacement – \$650,000 per unit
4. 5-Pole Switch – \$950,000 per unit

The proposed 20% upgrade using forced air cooling is stated to be conceptually feasible but requires significant investment in engineering and equipment. To achieve the full, upgrade desired per unit complete bus replacement provides the more economical solution. A more modest upgrade may be feasible by commissioning a study of the existing bus system.

4.2 GENERATOR STEP-UP TRANSFORMERS

The existing transformers are operating at near capacity at Helms with only a 5MVA margin leaving it 66MVA below the desired rating. Black & Veatch transformer specialists advised that this magnitude requires an OEM study, in this case, by General Electric. The thermal dissipation required for a 15% uprate may be feasible with additional cooling however the increase in core flux may be beyond the capabilities of the transformer core steel.

PG&E recently sought bids for new GSUs for Helms based on their remaining life. Waukesha – SPX provided updated budgetary materials pricing of \$1,600,000 per transformer/\$4,800,000 per generating unit. Freight, rigging, and installation are required in addition to this pricing.

4.3 230KV CABLES AND POTHEADS

Like the 18kV components the 230kV cables and potheads are currently operating near their design limit. This is an engineer system with a stated ampacity of [REDACTED] amps for both the cable and potheads per PG&E record drawings.

Replacing the cable system will be required to increase the generation capacity. Pricing on this complex cable installation is not readily available, however materials are estimated at \$1,500,000 for the three units and spare cable. PG&E may have internal records of bids for cable replacement that could augment this data.

4.4 EXCITATION SYSTEM

The Helms generators have modern ABB Unitrol static exciters. These units are compatible with a generator uprate but may not be able to produce the rated 0.9 power factor due to their upper limit. Extrapolating the current generator field rating it is estimated the exciters can achieve a generator 54 MVA uprate. An uprate study is required to validate the required excitation current. Unlike the main power conductors in the 18kV and 230kV system, the exciters are expected to accommodate most of the desired unit uprate. Cost saving could be achieved in this area by either reducing the uprate to match the existing exciter current limit or modifying the operating limits of the exciters.

In the latter scenario, the real power uprate is realized but VAR production is limited by the excitation system. A power factor of 0.93 to 0.95 is likely achievable at full megawatt load. This compromise requires operational input, however as long as all operating units are not at 100% output for megawatts and megavars this will not require significant operational compromises. A future uprate study can confirm the precise limits.

4.5 GOVERNORS

The originally installed governors have subsequently been replaced with a digital governor system. Further investigation would be required to determine if the electronic and the hydraulic governor components are suitable for uprated pump-turbines. At a minimum, the servomotor stroke will likely need to be increased to open the wicket gates further, allowing an increase in water flow to the pump-turbine.

4.6 TRANSMISSION SYSTEM

The two Helms-Gregg lines leaving Helms Powerhouse are each rated for [REDACTED] amps or [REDACTED] MVA for summer normal load. Without modification these lines can accommodate an additional [REDACTED] MVA of generation from Helms. This allows an uprate to [REDACTED] MVA per generating unit. Lines would

be operating at the summer normal rating and the substation components can accommodate this loading. Operationally, the two lines are required to be carefully balanced as there is minimal margin before the line is placed in an overload condition.

Based on the Helms-Gregg ratings information provided by PG&E the multiple components share the 1,908 amp summer normal limitation. Under summer emergency or winter ratings most items have much higher ratings, however one disconnect switch is stated to have a [REDACTED] amp limit in all seasonal conditions limiting the line to about [REDACTED] MVA. A transmission study may be able to increase the ratings of these lines or identify and remove weak links in the substations. This becomes more necessary if the fourth unit scenario finds a unit in excess of the 131 MVA line capacity is desirable.

4.7 UNIT VARIABLE SPEED CONVERSION

For increased flexibility of operation, one or more units could be converted to variable speed operation. This would allow a generator to operate over a wider range and more quickly switch between pump and generation modes. Variable speed conversion can be considered independently or concurrently with a peak generation upgrade. The benefits of variable speed operation are discussed in greater detail in Section 6.0.

Equipment required for this conversion includes a multi-winding transformer to mitigate harmonics and a medium voltage variable frequency drive. Using the full converter system eliminates the need for a 5-pole switch and pony motor as drives can both reverse the phase sequence and allow the motor starter to produce 100% torque at 0% speed with no motor inrush current. Cycling of the 230kV breaker can be reduced as it is not necessary to open the breaker when the variable speed unit is idle.

5.0 Scope of Work for Potential Unit 4

This section describes the scope of work for installing a new pump-turbine in a location directly west of the existing powerhouse cavern. Although the specific size of the new unit has not been determined, the scope of work provided below is general and would be applicable to a new unit of any size. Figure 5-1 through Figure 5-3 show conceptual sketches of preliminary tunnel and penstock routing, preliminary layout of major electrical equipment, and an electrical one-line drawing respectively. All sketches assume the largest equipment layout (400 MW unit with full converter) to show worst case cavern excavation limits. If a smaller unit is preferred, the size of all components will be reduced accordingly. Selection of a fixed speed alternative will also provide a small reduction in cavern size but would not affect the tunnel and penstock sizes.

5.1 CAVERN EXPANSION

To accommodate expansion of the underground powerhouse several considerations must be addressed related to constructability and maintenance of existing operations during construction. Access to the cavern expansion for construction would be from the Powerhouse Bypass Tunnel that bifurcates from the existing Powerhouse Access Tunnel and ultimately leads to the Drainage Gallery. The invert elevation of this access tunnel in the vicinity of the cavern expansion is roughly [REDACTED] ft, which is in the mid-level of the future cavern. Therefore, an upward sloping drift from the bypass tunnel on the south edge within the future cavern will be required to facilitate excavating the cavern in stages from the roof downward using controlled blasting techniques. Exposing the cavern roof initially will allow for ground support systems to be installed to stabilize the excavation. The lifts of these stages (benches) will need to be designed to prevent blasts from damaging existing infrastructure and it is anticipated that bench thicknesses in the cavern will be less than typical to control vibrations. In addition, consideration may need to be given for the installation of a temporary wall at the western end of the existing powerhouse to isolate the construction activities from the operating floor of the powerhouse, as a vast majority of the tunnel activities will be conducted from the future cavern excavation. This would include blasting, muck hauling, groundwater pumping, and labor, equipment and material ingress/egress, etc.

As the cavern excavation progresses downward sequencing of the work will be critical to allow access for construction of the Drainage Gallery extension, if needed, above Penstock 4; excavation of the offset cavern housing electrical equipment and buried high voltage lines that will be connected to the existing cable tunnel; penstock tunnel 4; and lastly the fourth draft tube tunnel. It is anticipated that the current Powerhouse Bypass Tunnel will not provide access to the Drainage Gallery once the cavern expansion is complete. The construction methodology and work sequencing of the tunnels are discussed in more detail in the following section, including options for making the connections to the live penstock manifold and tailrace tunnel.

5.2 WATER CONVEYANCE

A fourth tunnel currently is connected to the penstock manifold that is plugged with concrete to isolate the Powerhouse Bypass Tunnel and an existing tunnel that is connected to the Powerhouse. It is anticipated that to expand the facility with a fourth generating unit a new tunnel will be constructed to connect this fourth tunnel upstream of the concrete plug to the cavern expansion being accessed through the Powerhouse Bypass Tunnel. This tunnel is expected to be at a similar profile as the other three penstocks as well as have the same finished diameters ([REDACTED]) up to the Powerhouse. A preliminary layout of the new tunnel and penstock sections is shown in Figure 5-1. The new penstock tunnel will be constructed using controlled blasting techniques with minimal rock cover/separation from the Powerhouse Bypass Tunnel near the connection. The

connection to the active fourth tunnel will be made upstream or near the north end of the concrete plug at an offset angle to the concrete plugged tunnel to create some separation between Penstock 4 and the open tunnel that leads to the Powerhouse. While hydraulics is an important consideration, the angle of the connection should also consider constructability given a larger angle will be easier to construct in a timely fashion and provide additional separation distance from the concrete plugged tunnel. This separation distance will be critical to ensure adequate rock is present between these two tunnels to address the structural capacity of the system. As part of design, this particular issue will need to be analyzed to determine if the existing concrete plug needs expanding to the south, which may then require modifications to the Drainage Gallery. Penstock 4 will be approximately two tunnel diameters under the Powerhouse operating floor, which has proven to be adequate during construction and operations in the other penstocks.

The Unit 4 draft tube tunnel will exit the Powerhouse at a similar elevation as the other units and will connect to the tailrace tunnel downstream of the other units' draft tubes. This drill and blast tunnel will cross under the Powerhouse Access Tunnel and Transformer Vault Access Tunnel at what appears to be an adequate separation distance of more than 40 feet.

Connections of the Unit 4 tunnels to both the penstock manifold and tailrace tunnel will require a system outage. A few feasible options exist to make these connections. An option that would require only one outage would include completing the construction of Unit 4 and the associated tunnels prior to making both connections. This would involve leaving a rock plug between the penstock and penstock manifold to be removed to make the connection. Access to remove this rock plug during an outage could occur through a new bypass tunnel constructed parallel to and west of the existing Powerhouse Bypass Tunnel. This new bypass tunnel would intersect the penstock at the connection point to allow the rock plug to be removed and the tunnel connection completed with concrete and steel. All material and construction activities for this connection would be accessed from this new parallel bypass tunnel. Upon completion of this connection a portion of the new bypass tunnel nearest the connection would be plugged with concrete. During this same outage the connection of the draft tube to the tailrace tunnel would be completed. Similarly, this would also require removal of a rock plug and lining of the tunnel connection with concrete. Access to make this connection could come from a short tunnel and shaft sunk off to the south side of the Transformer Vault Access Tunnel. Upon making this connection the shaft would be backfilled.

As an alternative for connecting Penstock 4, an outage could be conducted prior to the build-out of Unit 4. This approach would require the cavern excavation and penstock tunnel to be excavated up to the connection and a system outage occur to allow the connection to be made to the penstock manifold. Downstream of this connection a valve would be installed in the penstock that could be closed to allow the remainder of the project to be constructed with the three units online. We would expect this approach to require a longer system outage than using a new bypass tunnel to make the connection and this connection approach would still require a second system outage to connect the draft tube to the tailrace tunnel. However, there may be some construction cost efficiencies with this two-outage approach.

5.3 GEOTECHNICAL CONSIDERATIONS

The rock in the area of the proposed cavern expansion has been described predominantly as blocky, fresh meta quartz diorite. The blocky nature of the rock is due to fracturing along planes of schistosity. The joints are typically poorly defined and discontinuous in the schistose meta quartz diorite; however some joints are well defined, show indications of weathering and produce groundwater. This blocky massive rock has shown it can be supported over wide spans in the

existing Powerhouse and associated tunnels using traditional ground support type systems, including rock bolts, steel sets and shotcrete.

Shear zones in the rock have been mapped previously in the project area. Based on this mapping it appears that the cavern expansion may encounter a shear zone near the connection to the west wall of the existing Powerhouse and the proposed tunnel for Penstock 4 will likely encounter moderately to highly sheared zones of rock for [REDACTED] feet of the alignment. The need for grouting this shear zone in areas not previously grouted (1983) along the tunnel alignment will need to be determined. It is anticipated any grouting would be done in front of the cavern/tunnel heading (pre-excavation grouting) as the excavations advance.

Additional geotechnical borings and laboratory and in-situ testing data to characterize the rock and potential for groundwater inflow will be needed. Particular areas of interest include the subsurface characteristics near the roof of the proposed cavern, cavern walls, and areas of low cover/separation from the existing tunnels and the proposed Penstock 4 tunnel and draft tube.

5.4 PUMP-TURBINE SELECTION

Preliminary selections (shown in Table 5-1 and Table 5-2) for the generating equipment considered rotating speed, submergence, main dimensions and ratings in all operating conditions, including part load generation and pumping. The selections presented in this report were made based on experience of the Black & Veatch team, gained from long-term work with major pump-turbine suppliers. The final selection would be optimized with participation of OEMs, to create a hydraulic design based on their experience and specifically targeted for the needs of this project.

Table 5-1 Summary of Fixed Speed Pump-Turbine Characteristics

PARAMETER	UNIT OF MEASURE	400 MW	300 MW	200 MW	100 MW
Pump-turbine runner diameter	in	209	173	146	105
Synchronous speed	rpm	360	450	514	720
Minimum generating output	MW	204	153	102	51
Minimum pumping power	MW	372	295	184	96
CL elevation	ft	6240	6240	6240	6240
Minimum submergence	ft	200	200	200	200

Table 5-2 Summary of Variable Speed Pump-Turbine Characteristics

PARAMETER	UNIT OF MEASURE	400 MW	300 MW	200 MW	100 MW
Pump-turbine runner diameter	in	182	159	136	110
Synchronous speed	rpm	450	514	600	720
Speed variation	%	0-100%	0-100%	0-100%	0-100%
Minimum generating output	MW	82	61	41	20
Minimum pumping power	WM	265	198	145	74
CL elevation	ft	6210	6210	6210	6210
Minimum submergence	ft	230	230	230	230

5.5 BALANCE OF PLANT ELECTRICAL EQUIPMENT

The fourth unit will require a similar amount of equipment to the existing three units including a new 480V station service transformer, excitation transformer, medium voltage iso-phase buswork and a high voltage cable connection to the Helms substation. If a variable speed unit is selected, the pony motor start system and 5-pole switch are not required.

Equipment can be arranged similarly to Units 1-3 in the expanded cavern space with local controls on the governor, exciter, and inverter control panels around the generating unit. Iso-phase bus will connect to the variable frequency drive and between the drive and the generator step up transformer. The 230kV cable tunnel will be extended to the location of the Unit 4 transformer and additional cable racks installed for Unit 4 cables. A preliminary layout of the major electrical equipment is shown in Figure 5-2 and an electrical one-line diagram showing the new unit is shown in Figure 5-3.

Substation expansion will require a new unit breaker adjacent to the Unit breaker. This 230kV breaker can tie directly into the line tie bus via a manual disconnect switch. It is anticipated that the existing cable tunnel will be extended on to reach the new breaker. Substation tie bus components connecting Helms-Gregg Lines 1 and 2 including breakers 250 and 260 will require modifications to accommodate the new generating unit. Detailed evaluation of the affected conductors should be performed in conjunction with the 230kV line and substation evaluation.

Manual operation of the unit is not anticipated with a full converter variable speed. 230kV breaker controls and unit-start stop will be incorporated into the Helms control room.

A fourth station service transformer and distribution equipment will be required to provide 13.8 and 480V auxiliary power. The location of the station service connection cannot be unit connected like Units 1-3 as the unit voltage varies based on the inverter loading. Distribution line connection or a 230kV-13.8kV and 13.8-480V transformer is expected to be required. Optionally the new station 13.8kV transformer could be connected to the existing motor bus to simplify the pump mode starting process. Station service options will be determined during detailed design when the Unit 4 aux loads are available.



Figure 5-1 Preliminary Layout Sketch of New Tunnels and Penstock

BLACK & VEATCH | Scope of Work for Potential Unit 4

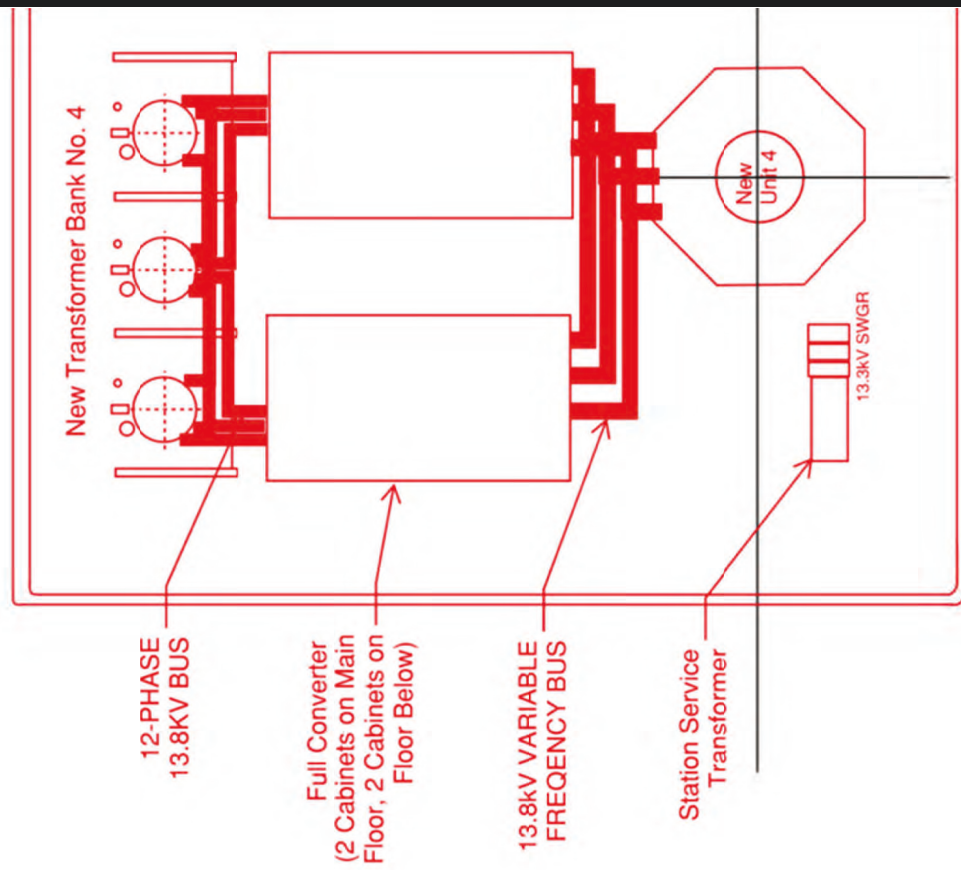


Figure 5-2 Preliminary Layout Sketch of Major Electrical Equipment Layout (new 400 MW unit)

BLACK & VEATCH | Scope of Work for Potential Unit 4



Figure 5-3 Preliminary Electrical One Line Diagram

BLACK & VEATCH | Scope of Work for Potential Unit 4

6.0 Alternative Technologies for Potential Unit 4

In the years since the original pump-turbine units were installed at Helms, there have been significant advances in pump-turbine technology which greatly increase the operational flexibility of the units. These developments include the use of variable speed technologies and Ternary style pump-turbine configurations. When considering the addition of a potential fourth unit, these modern technologies should be evaluated along with the traditional fixed speed design. This section will describe the various concepts and provide a high-level comparison including the technical advantages and disadvantages for each alternative.

Figure 6-1 shows a schematic illustration and comparison of the different technologies.

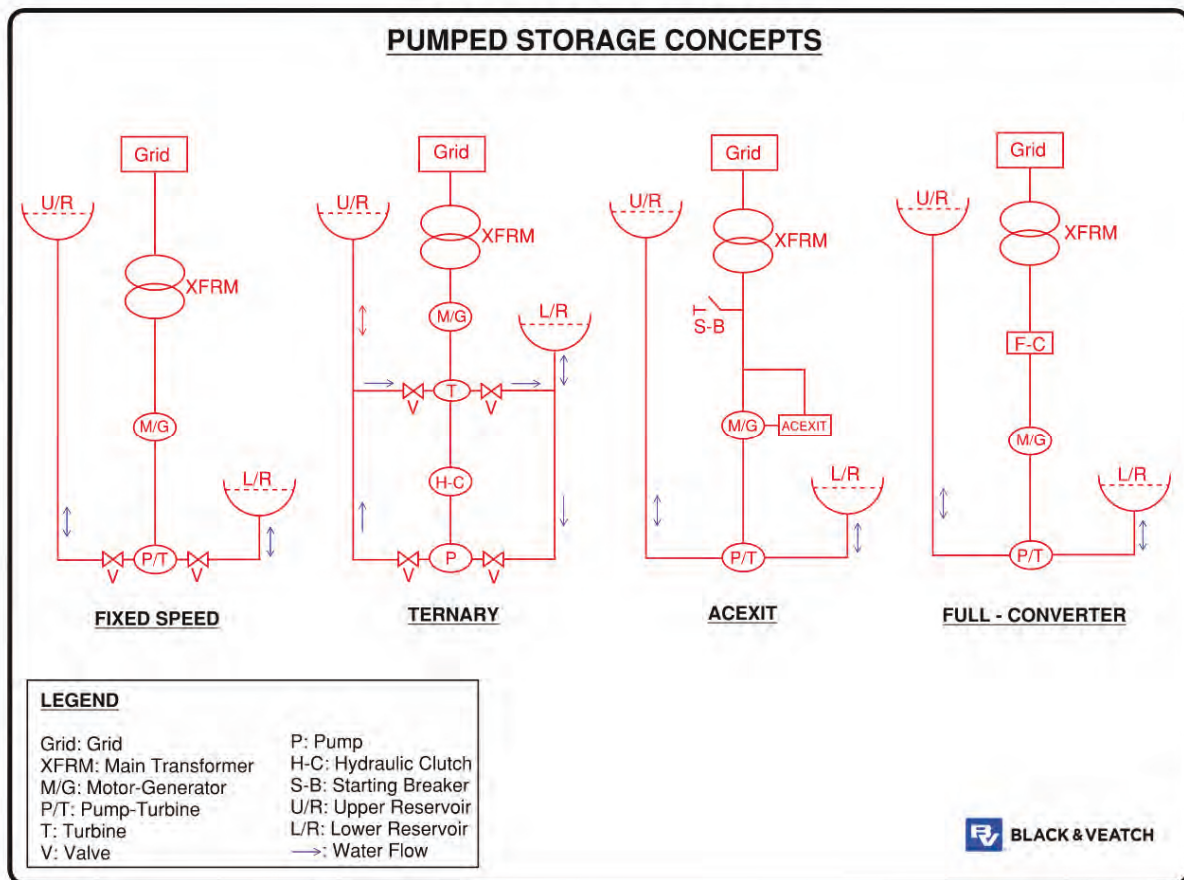


Figure 6-1 Schematic Comparison of Pump-Turbine Technologies

6.1 COMPARISON OF PUMP-TURBINE TECHNOLOGIES

6.1.1 Fixed Speed

In traditional, fixed-speed units, the motor-generator is connected to the grid via a block-transformer and the speed of the unit is defined by the grid frequency. The fixed speed solution is well proven with over 50 years of experience and hundreds of installations around the world. Every major pump-turbine supplier is capable of offering competitive products, based on a range of their own hydraulic designs.

There are several starting methods for fixed speed units including across the line start, back-to-back starting, and using a pony motor for starting. However, most modern plants now use a Soft Starting Frequency Controller (SFC) to start the units. In this type of application, the SFC utilizes power from the local power system. The output of the SFC is connected to the synchronous machine and the frequency is raised together with voltage from near zero values. The synchronous machine follows this increase of frequency/voltage up to rated speed at which time the unit is synchronized to the local power system. Then, the SFC is disconnected and the machine begins to operate in the normal pumping mode. In multi-unit plants, one SFC is switched from unit to unit to control the start-up process of the entire plant, including automatic acceleration and synchronization. The SFC is capable of accelerating the unit from zero to rated speed without subjecting the unit to detrimental high inrush currents or excessive damper winding heating.

Fixed speed pump-turbine units require a tailwater depression system (WDS) to dewater the runner for switching to pump mode. With the runner dewatered, the pump-turbine is accelerated to the lowest speed the unit can maintain when connected to the grid and then the main breaker is closed, and the AC excitation allows for further acceleration to the speed necessary to initiate pumping mode.

Table 6-1 Pros and Cons of Fixed Speed Units for Upgrading Existing Units

PROS	CONS
Large number of units in operation.	Limitations in pumping mode.
Proven technology.	Reduced operating range in generation mode.
Lower initial costs as compared to variable speed or ternary units.	Lower efficiency.
	Unit needs to rotate in condenser mode.

6.1.2 Variable Speed with AC Excitation

In the variable speed with AC excitation (ACEXCIT) configuration, the rotor of the induction motor-generator is fed via a three-phase AC power source. The stator of the motor-generator is coupled to the grid in the same way as the fixed speed configuration. However, instead of DC-Excitation an AC-Excitation system is utilized. The size of the ACEXCIT is defined primarily by the required speed range; the wider the operational range, the larger the power electronics required. Starting in pump mode is accomplished by short-circuiting the stator terminals of the motor-generator, and the pump-turbine is dewatered using a tailwater depression system (WDS) and accelerated up to the operational speed range. Alternatively, the ACEXCIT can be increased in size to provide the increased starting torque required to start the unit in water, if a WDS is not utilized.

The ACEXCIT configuration utilizes the same pump-turbine as considered for the fixed speed design, discussed above. The differences are related to the performance characteristics, resulting from the application of variable speed. In order to achieve a broader operating range in the pump mode, the submergence of the pump-turbine has to be greater (lower elevation) than in the case of a fixed speed machine.

In the generating mode, the variable speed allows the operation to be kept close to the best efficiency point across most of the head range. This results in substantially improved efficiency as compared with the fixed speed option. In pump mode, the variable speed allows for variation of the

input power and results in a wide operating range as compared to the fixed speed unit which is confined to a single pump curve. This is the most valuable feature of this kind of design.

Table 6-2 Pros and Cons of Variable Speed ACXCIT Units

PROS	CONS
Substantially wider operating range as compared to fixed speed units results in increased operational flexibility.	Higher initial cost than fixed speed units.
Generating efficiency substantially improved compared to fixed speed units.	Motor-generator is an asynchronous unit.
Allows for variation in the input power during pump mode.	Technology not familiar to existing Helms O&M staff.
Faster reaction time than fixed speed units.	Lower setting elevations required, which increases excavation costs.
Option to operate without WDS which would further speed up response time.	
Lower converter cost as compared to the full converter configuration.	

6.1.3 Variable Speed with Full Sized Converter

In the variable speed with full converter configuration, the synchronous generator is coupled to the grid via a full converter, which is designed for the nominal power of the system plus the reactive power required for the grid connection. Pump-turbine and motor-generator speed are not limited by the electrical system. However, the hydraulic design limits of the pump-turbine (cavitation, stability) must be considered. The pump-turbine can be started with the runner in water so a WDS is not necessary.

This configuration utilizes the same pump-turbine as considered for the fixed speed and ACXCIT designs discussed above. However, in this option, the pump-turbine can continuously vary operating speed from zero to the value slightly above the synchronous speed. The range of operation in the pump mode is defined by the generator-motor capacity on the high-power end and by the cavitation at low power. During generation, the wide range of speed will allow the unit to always operate at the best efficiency point for the equipment.

The converter has sufficient power to start the unit in the pump mode with the runner in water so a WDS is not needed. Moreover, very fast acceleration can be assured, to provide with ability for a very quick start. The control of the pump-turbine operation is the same as in the ACXCIT configuration.

The currently largest pumped storage unit in operation with Full-Converter Technology is 100 MW. However, there are several larger full-converter pump storage project in development including a 900 MW (3 X 300MW) project in which Black & Veatch is the Owner's Engineer.

Table 6-3 Pros and Cons of Variable Speed Units with Full Converter

PROS	CONS
Can start the unit with impeller in water	Large footprint.
Same motor generator as fixed speed (synchronous unit).	Higher cost than ACXCIT.
Highest operation flexibility.	Fewer full converter installations than ACXCIT or fixed speed.
Direct mode change from generation to pumping mode.	Largest currently installed full-converter to date is 100MW in Switzerland.
Fastest mode changes.	Higher initial cost than fixed speed units.
Dynamic support, reaction time faster than Fixed Speed unit.	Technology not familiar to existing Helms O&M staff.
Condenser mode without rotating unit.	Lower setting elevations required, which increases excavation costs.
No phase reversal switches, Generator Circuit Breaker (GCB), or start-up short circuit breaker required.	

6.1.4 Ternary

The ternary pumped storage configuration consists of a separate turbine and pump on a single shaft with an electric machine that can operate as either a generator or a motor. The turbine can be of either the Francis or Pelton design, depending on the hydraulic characteristics of the site. This means that the rotational direction of the unit is the same in generating and pumping mode. They are often the only solution for projects with very high head, but they can be applied for lower head projects as well. Traditionally, ternary units were installed in a horizontal arrangement with the motor-generator located in the middle between the single-stage pump and turbine. Over the past few years, a few vertical ternary units have been installed by utilizing a hydraulic coupling, or clutch, in the shaft between the pump and the turbine.

Without the need to change rotational direction, little changeover time is needed between pumping and generation modes, making it possible to respond faster to the grid variations. The turbine and pump can even operate simultaneously (in hydraulic short-circuit mode), and the turbine can be used to start the pump (further reducing changeover time). In this configuration the motor-generator is on top of the pump-turbine Unit.

Figure 6-2 shows the typical configuration of the major components and the waterflow within a Ternary configuration.

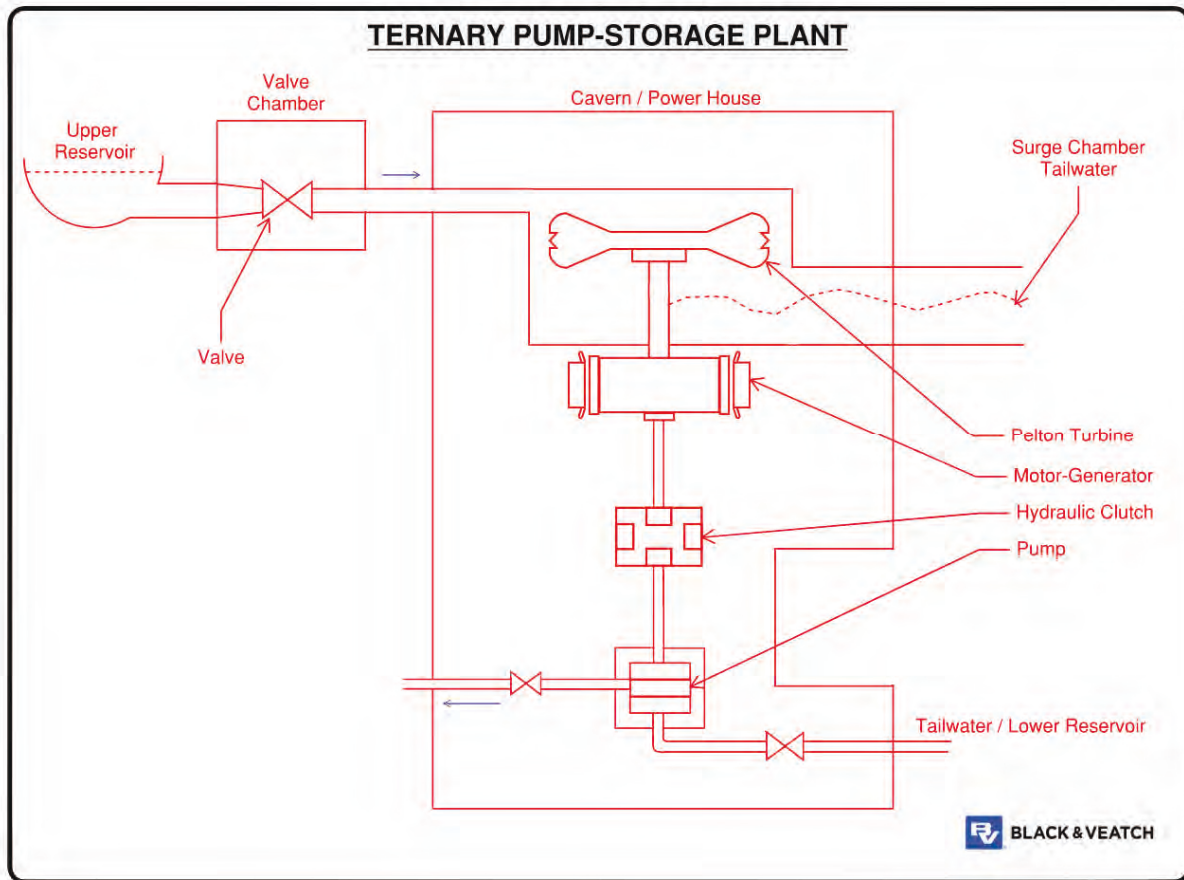


Figure 6-2 Typical Ternary Unit Configuration

The Powerhouse structure for ternary sets needs to be taller and wider since unit sizes are larger with a likely shaft length of over 200 ft. Significant tunnel works be required to accommodate the additional penstock and tailrace branch pipes. This would result in an entirely different cavern space than the existing powerhouse. Because of the high costs and extra complications associated with this design with only marginal benefits compared to the full converter configuration, the ternary style unit is not recommended for further evaluation.

Table 6-4 Pros and Cons of Ternary Units

PROS	CONS
Greatest regulation flexibility.	Highest initial cost.
Shortest transfer time.	Largest space requirements.
	Increased maintenance required.
	Slightly reduced overall efficiency compared to variable speed configurations.

Requires penstock and discharge tunnel bifurcations and associated shutoff valves and gates.

6.2 COMPARISON OF FIXED SPEED, ACEXCIT, AND FULL CONVERTER OPERATIONAL RANGES

Figure 6-3 shows the generating range for the 3 alternatives: Fixed Speed, ACEXCIT and Full Converter superimposed. In turbine mode, the operational ranges of the ACEXCIT and Full Converter configurations are the basically the same. Fixed speed units show that they are limited at lower heads, and reduced outputs.

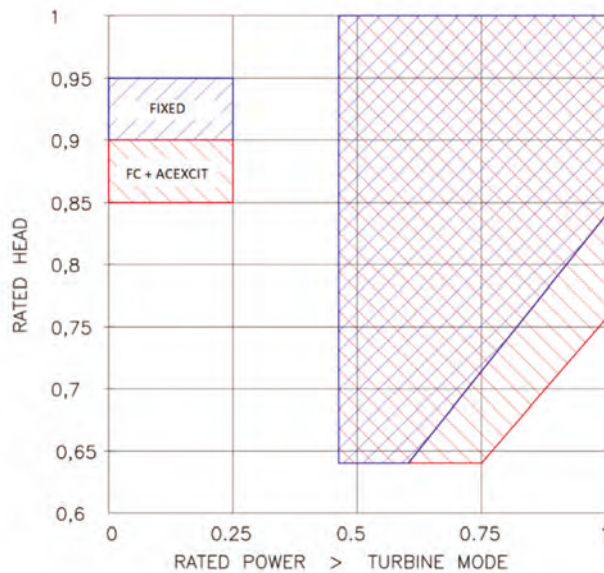


Figure 6-3 Turbine Mode Operational Ranges

Figure 6-4 shows the pumping range for the 3 alternatives: Fixed Speed, ACEXCIT and Full Converter superimposed. The Full Converter configuration allows for a wider operating range at lower heads as compared to the ACEXCIT configurations. The Fixed Speed unit is limited to a single pumping curve.

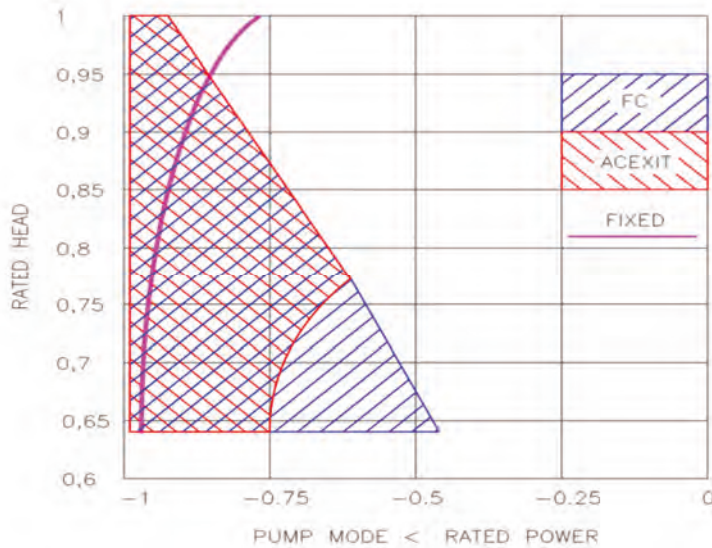


Figure 6-4 Pump Mode Operational Ranges

6.3 COMPARISON OF FIXED SPEED, ACEXCIT, AND FULL CONVERTER CHANGE OF OPERATING MODE

For both Fixed Speed and ACEXCIT configuration, changes between operating modes are very similar. To change to pump mode, the pump-turbine has to be dewatered and then restarted, resulting in a start-up time in the range of 180 to 300 seconds. On ACEXCIT with an enlarged converter and no WDS, this time could be reduced somewhat.

The Full Converter configuration offers more flexibility during transitioning, as the torque which can be applied at low speeds is large enough to accelerate the motor-generator in any direction, even with the pump-turbine in operation. No dewatering of the pump-turbine is required, so the change of operation mode from stop to pump mode is achievable in approximately 30 seconds and a transition from turbine mode directly to pump mode is achievable in approximately 45 seconds.

Transition diagrams for Fixed Speed, ACEXCIT and Full Converter configurations are provided in Figure 6-55 and Figure 6-6. The transitions are the same for Fixed Speed and ACEXCIT

configurations.

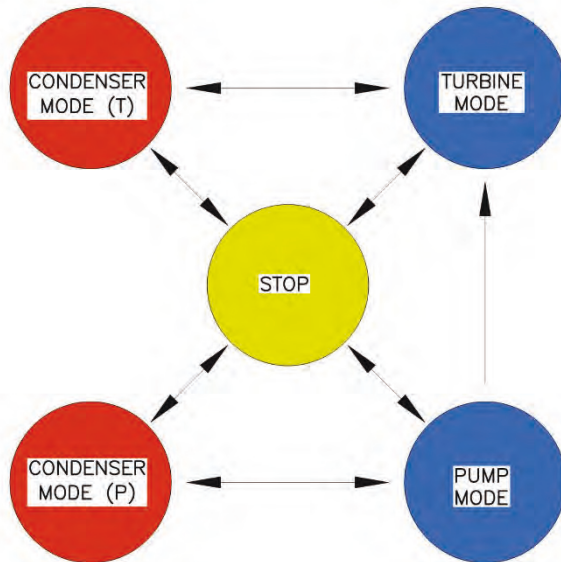


Figure 6-5 Operating Mode Transition Diagram for Fixed Speed and ACEXCIT Configurations

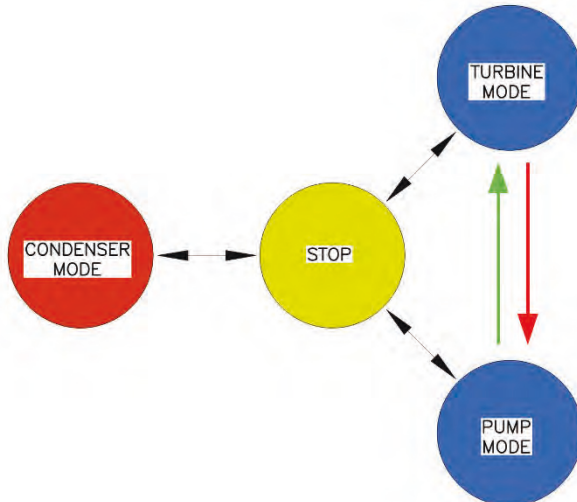


Figure 6-6 Operating Mode Transition Diagram for Full Converter Configurations

6.4 POWERHOUSE LAYOUT IMPACTS

The evaluation of the fixed speed versus variable speed units will have impacts on the powerhouse civil costs. As noted above, the setting depth of the pump-turbine will vary depending on use of fixed speed or variable speed equipment. For the fixed speed alternative, the setting elevation

would be at elevation 6,240 like the existing units and would be the highest setting depth of the various alternatives considered in this evaluation. For the variable speed alternatives, the setting depths would be lowered to approximately 6,210. For the Ternary unit, the estimated setting elevation would be lowered even further. Lowering the pump-turbine elevation results in additional excavation for the powerhouse cavern addition, new penstocks, and new discharge tunnel.

For this evaluation, it was assumed that the powerhouse plan dimensions would be similar for the Fixed Speed and ACExcIT with/without tailwater depression alternatives. However, for the full converter alternative, significant additional space within the powerhouse would be required to house the full converter and its lineup of equipment. The Ternary unit alternative would require the most space in the powerhouse since Ternary units are physically taller and wider than the other alternatives. Penstock and tailrace tunnels will both require an extra bifurcation and additional mechanical equipment such as gates and valves would be required.

6.5 RELATIVE COST COMPARISON

This section presents a comparison of the alternatives considered, including their capital cost and annual Operation and Maintenance Cost.

6.5.1 Capital Costs

Table 6-5 shows the estimated difference in equipment capital cost for the different alternatives considered. As may be expected, the lower cost option is the one that offers the least operational flexibility, and the option with the highest operational flexibility is also the highest cost option.

The cost evaluation is comparative in nature and does not represent total installed capital costs for the equipment or the powerhouse. Equipment cost items such as installation, testing and indirect costs are not considered as they are expected to be generally proportional to the comparative costs indicated and are not expected to affect the comparative evaluation results. These costs are also included in the overall cost estimates provided in Section 7.0.

Table 6-5 Cost Comparison for 400 MW Pump-Turbine Configurations

PUMP-TURBINE CONFIGURATION	RELATIVE CAPITAL COST
Fixed Speed	Base
Variable Speed - AC Excitation with WDS	Base + \$31M
Variable Speed – Full Converter	Base + \$35M
Ternary	Base + \$78M

6.5.2 Annual Operation & Maintenance Costs

Annual operation and maintenance (O&M) costs for the alternatives evaluated are considered to be comparable, although there are differences between the alternatives, reflected more on the type (specialty) of maintenance staff rather than the number of staff.

Comparing the fixed speed alternatives to the variable speed alternatives, the primary differences are the need for a WDS and SFC; the SFC requires regular periodic maintenance such as the

replacement of air/cooling water filters etc. For the WDS regular inspection/maintenance of the compressors and control devices is necessary.

For the ACEXCIT alternatives, the WDS and the power electronics require routine maintenance. In comparison to an SFC, more cooling water pumps/circuits are involved, however the ACEXCIT system as well as the SFC system will have both significant monitoring capabilities build-in, aiding the involved maintenance staff.

The full converter alternative has a significant reduction in the number of breakers involved, and no WDS is required, however significantly more power electronics are involved, requiring significantly more cooling capacity than SFC or ACEXCIT configurations.

The ternary configuration can expect to require the most maintenance due to the complexity of the pump-turbine and the additional shutoff valves and discharge gates required.

7.0 Cost Estimates

Black & Veatch prepared AACE, Class 5 cost estimates for each of the alternatives utilizing internal experience and knowledge from recent, similar pump storage feasibility studies. The result is a baseline cost with a range of -20 percent or +50 percent. Costs developed are for full engineering, procurement, and construction. Indirect costs shown include costs associated with contractor general conditions, contractor overhead and profit, startup and commissioning, insurance, and tax but do not include PG&E labor costs or permitting costs. Cost also do not include any required modifications to substations or transmission lines required to transmit the additional energy generated. They also do not include costs for potential modifications to the existing surge chambers which may be required due to the increase in flow through the tunnels. A summary of the cost estimate for each alternative is outlined below.

The cost estimates include a contingency equal to 30% of the estimated direct costs. As the alternatives are further developed with additional studies and design, the contingency will be reduced. One of the largest cost drivers for the project is the equipment cost. During the next phase of the project, budgetary quotes should be solicited for major equipment to further refine the project costs.

7.1 ALTERNATIVE 1 - UPRATE OF EXISTING UNITS TO 460 MW EACH

Table 7-1 shows the estimated costs associated with uprating the existing three units to 460 MW each. The costs include rewinding Units 1 and 3 similarly to the recently rewound Unit 2 as well as replacing all of the existing runners with new ones that have been optimized for the higher flow and lower head conditions. Costs for replacing the TSVs with new ones that are designed for the higher flow are not included since PG&E is already in the process of procuring those new valves.

Table 7-1 Parametric Cost Estimate for Uprating the Existing Units

DESCRIPTION	COST
Rewind Units 1 and 3	\$24,000,000
Procure New Runners	\$111,000,000
Electrical Equipment Upgrades	\$21,000,000
Equipment Installation	\$39,600,000
Total Direct Costs	\$195,600,000
Contingency	\$51,500,000
Indirect Costs	\$81,300,000
Total Parametric Cost Estimate	\$328,400,000
Estimate Range	\$263-493M
Cost/Installed kW Range (165 MW Uprate)	\$1,594-\$2,988

7.2 ALTERNATIVE 2 – INSTALL A NEW UNIT 4

Table 7-2 shows the estimated costs associated with installing new fixed speed pump-turbines of various sizes. The costs include civil/structural work associated with expanding the powerhouse cavern as well as installing a new penstock and intake and discharge tunnels. For this initial estimate, the cost of the cavern expansion is assumed to be constant for all of the various unit sizes. Relatively small reductions in cavern expansion costs can be expected if a smaller unit is utilized and those costs will be updated once a unit size is selected and OEM equipment vendors have been engaged. Costs shown below would be increased by approximately 20% if a variable speed configuration is preferred.

Table 7-2 Parametric Cost Estimate for Installation of a New Fixed Speed Unit

DESCRIPTION	400 MW	300 MW	200 MW	100 MW
Cavern Expansion	\$72,800,000	\$72,800,000	\$72,800,000	\$72,800,000
Tunnels	\$15,800,000	\$15,200,000	\$12,200,000	\$8,300,000
Penstock	\$9,800,000	\$9,300,000	\$6,300,000	\$3,300,000
Pump-Turbine	\$59,000,000	\$42,000,000	\$30,000,000	\$18,000,000
BoP Mechanical	\$13,700,000	\$11,100,000	\$9,600,000	\$8,000,000
BoP Electrical	\$10,000,000	\$8,800,000	\$7,900,000	\$7,100,000
Equipment Installation	\$24,800,000	\$18,600,000	\$14,300,000	\$9,900,000
Total Direct Costs	\$205,800,000	\$177,800,000	\$153,100,000	\$127,400,000
Contingency	\$61,800,000	\$53,300,000	\$45,900,000	\$38,200,000
Indirect Costs	\$97,600,000	\$84,200,000	\$72,500,000	\$60,400,000
Total Parametric Cost Estimate	\$365,300,000	\$315,300,000	\$271,500,000	\$226,000,000
Estimate Range	\$292-548M	\$252-473M	\$217-407M	\$181-339M
Cost/Installed kW Range	\$730-\$1,370	\$840-\$1,577	\$1,085-\$2,035	\$1,810-\$3,390

7.3 ALTERNATIVE 3 - UPRATE THE EXISTING UNITS AND INSTALL A NEW UNIT 4

Table 7-3 shows the estimated costs associated with uprating the existing three units to 460 MW each and installing a new 400 MW, fixed speed pump-turbine. The costs include both scopes of work described in Sections 7.1 and 7.2.

Table 7-3 Parametric Cost Estimate for Uprate of the Existing Units and Installation of a New, 400 MW Fixed Speed Unit

DESCRIPTION	COST
Uprate Cost from Table 7-1	\$328,400,000
New Unit Cost from Table 7-2	\$365,300,000
<i>Total Parametric Cost Estimate</i>	<i>\$693,700,000</i>
Estimate Range	\$555-\$1,041M
Cost/Installed kW Range (420 MW PH Increase)	\$1,321-2,479

8.0 Recommended Next Steps

Based on the results of the hydraulic study and the cost estimates developed, it appears that adding additional generation at Helms is viable. Considering that the dams and water conveyance systems are already existing, utilizing the available hydraulic capacity to produce additional pump storage generation would result in one of the most cost-effective pumps storage projects currently in development. Expanding the existing facility also greatly reduces permitting risks and complexity compared to a new green field pump storage project. If PG&E wishes to continue investigating the potential for increasing the generation output at Helms, the following next steps are recommended:

Regulatory

- Include proposed uprate/capacity addition in upcoming FERC re-licensing.
- Work with CAISO and CPUC to show a commercial need and estimated cost for future planning studies.

Transmission

- Explore options for interconnection and transmission for the additional capacity at Helms.
- Conduct a transmission line and substation capacity study to determine scope of work required to upgrade the lines from their current rating of 1,520 MVA/1,368 MW summer normal total.

Hydraulics

- Conduct targeted CFD analyses of specific key locations which may potentially include: TSV through existing turbine inlet, tunnel and penstock bifurcations, bottom of incline shaft, and intake gates to confirm assumed velocity limitations are acceptable.
- Revise the existing transient analysis considering the increased flow and the new turbine selections to determine if the existing surge chambers would need to be modified.

Additional Studies/Preliminary Design

- If moving forward with uprating the existing three units, perform a detailed uprate study which will analyze the existing pump-turbine units in detail to determine the scope of work involved with the uprate including selection of the new runners optimized for the higher flow, lower head conditions.
- If moving forward with one of the Unit 4 concepts, select 1-2 alternatives to be refined through development of a 10% level design including OEM equipment selection and quotations. Consideration should be given to the optimal size of the new unit and whether variable speed technology will be utilized.

Appendix A. Electrical Equipment References

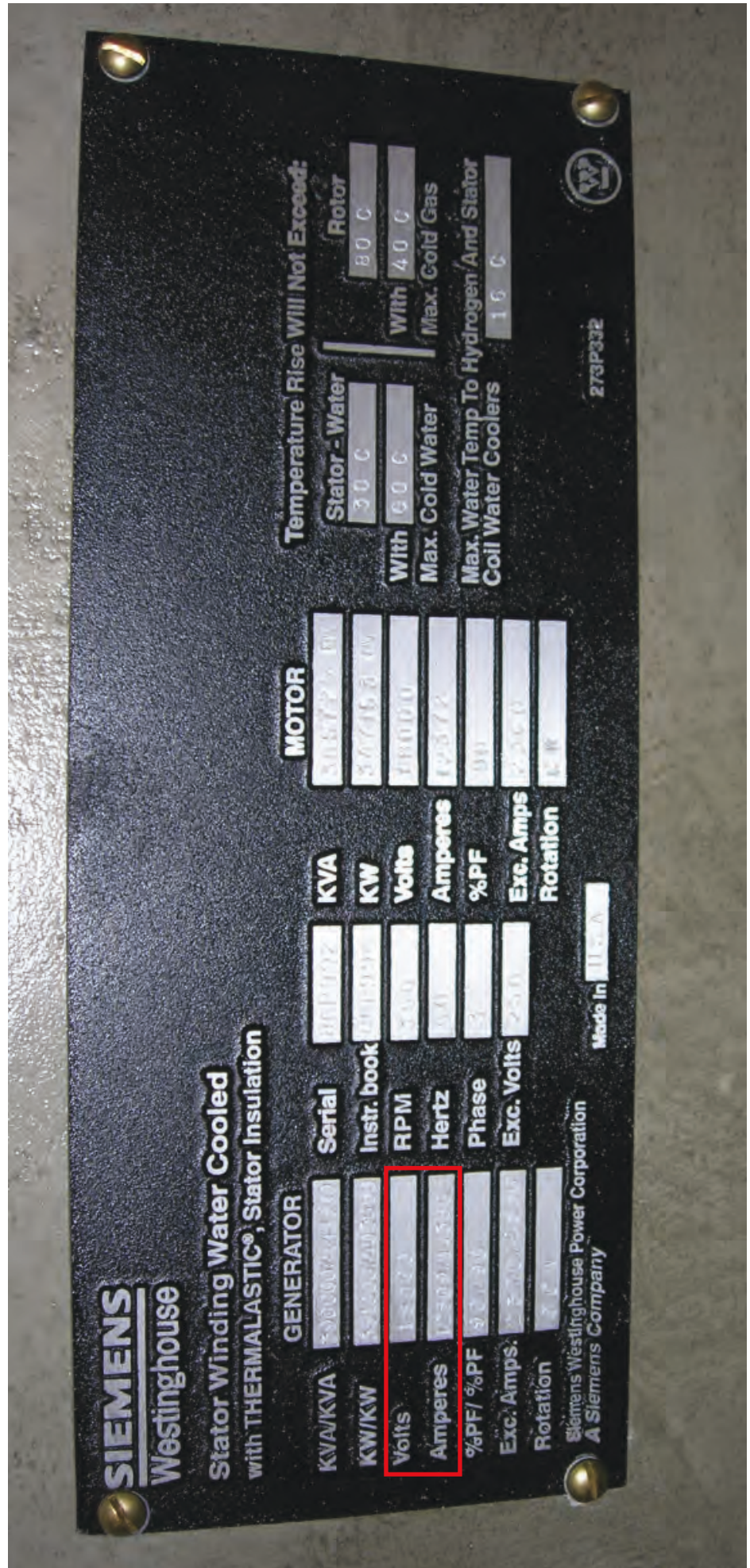


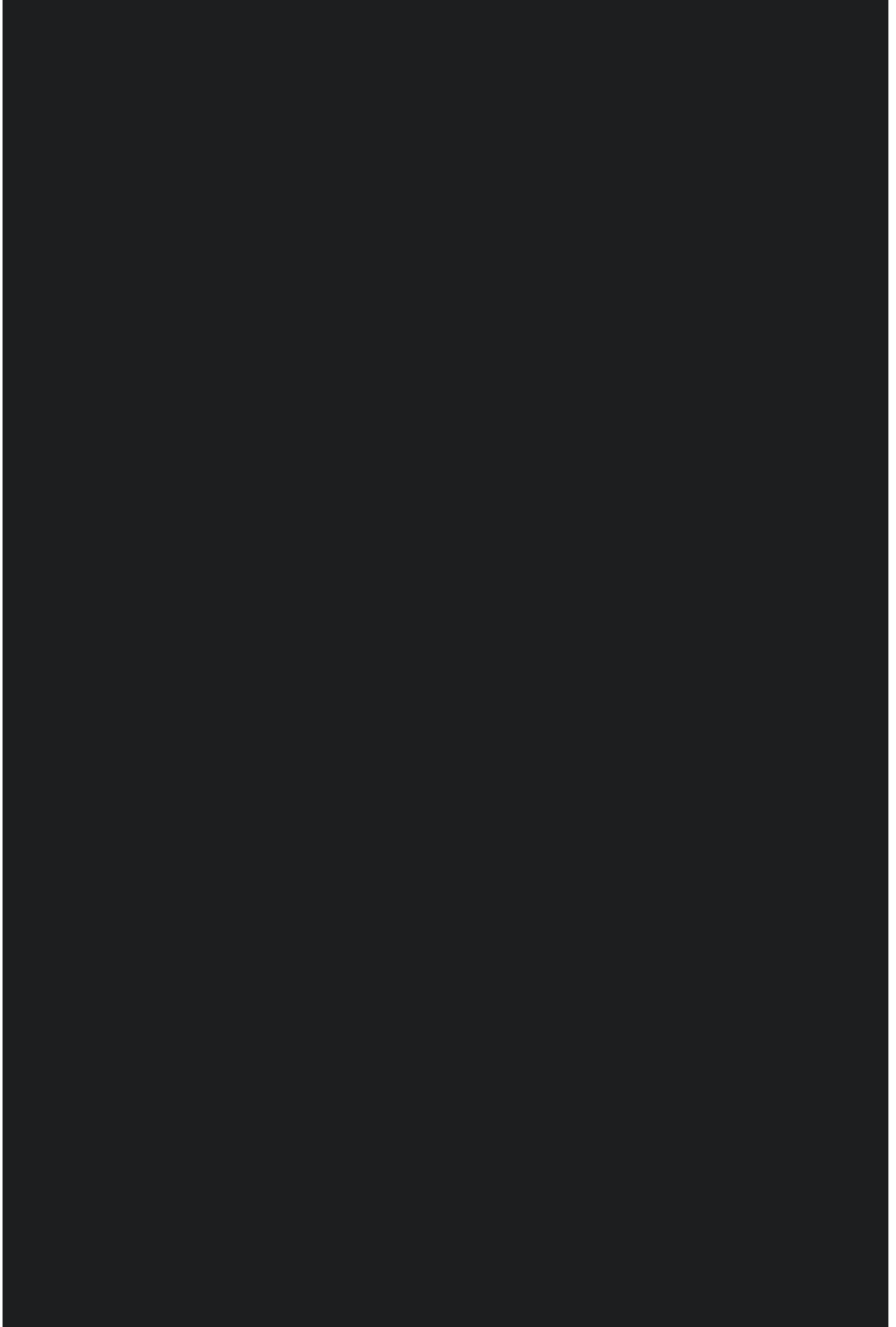




HELMS GENERATOR NO. 1

NAMEPLATE PHOTO

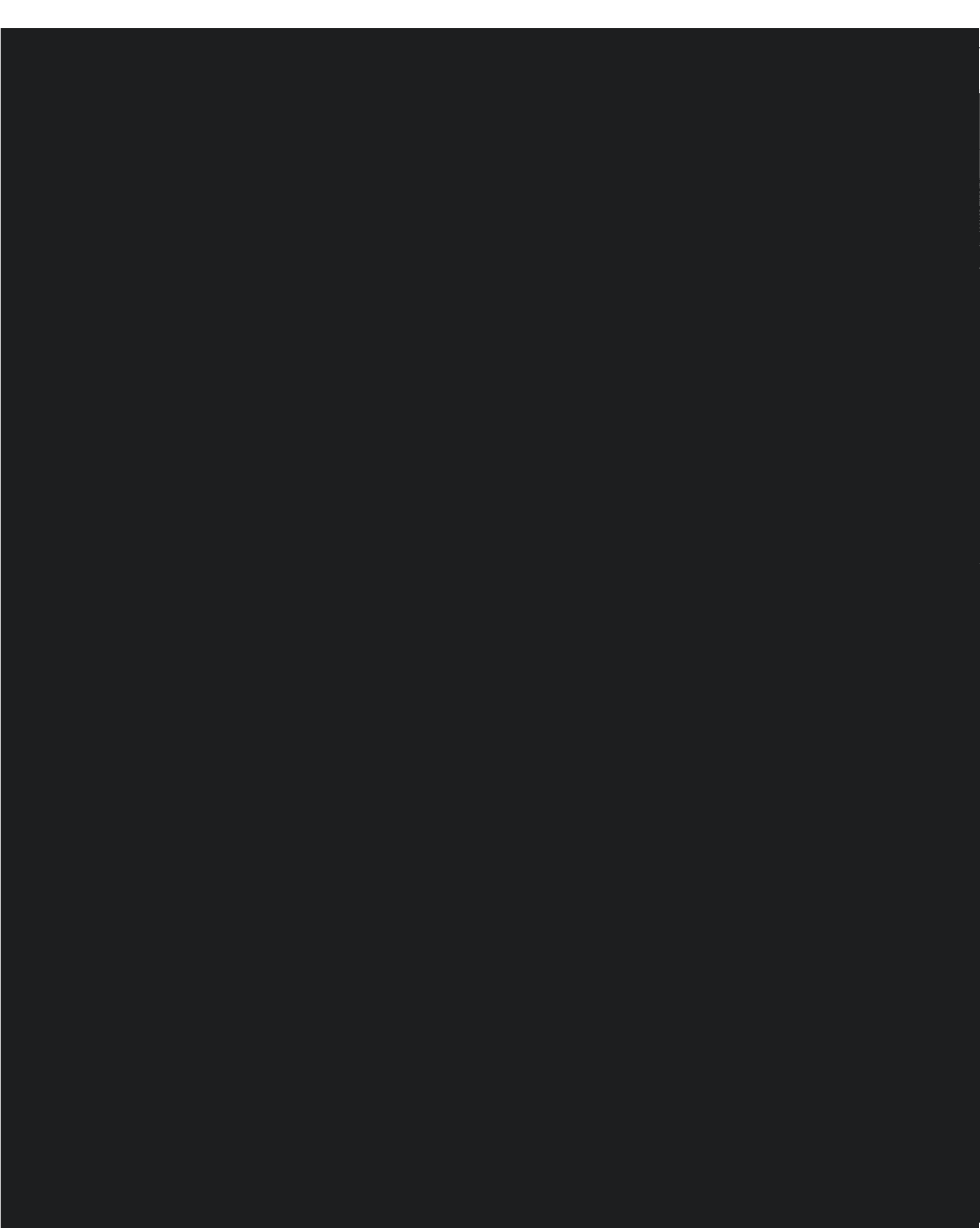


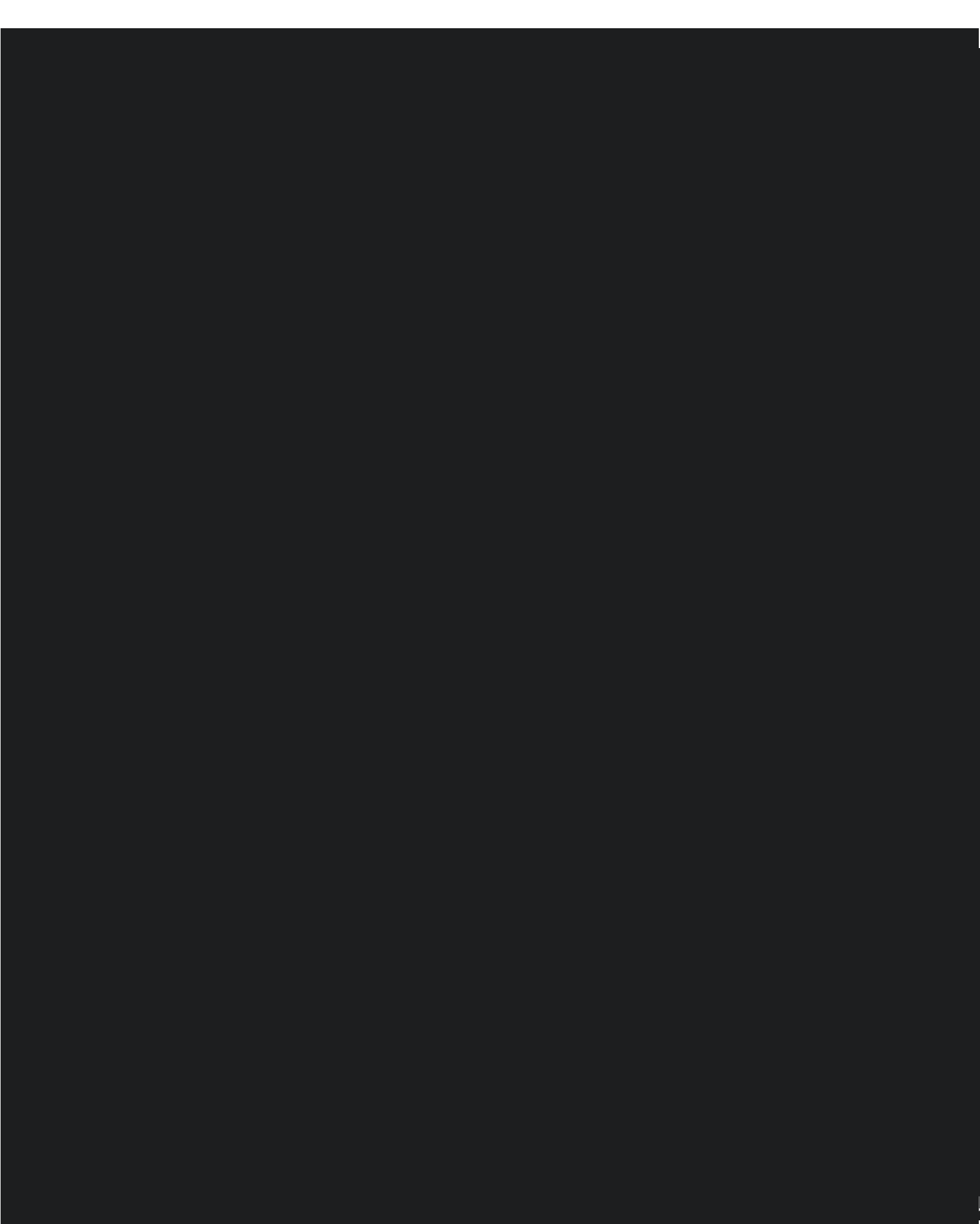


HELMS GSV NO. 1 NAMEPLATE PHOTO

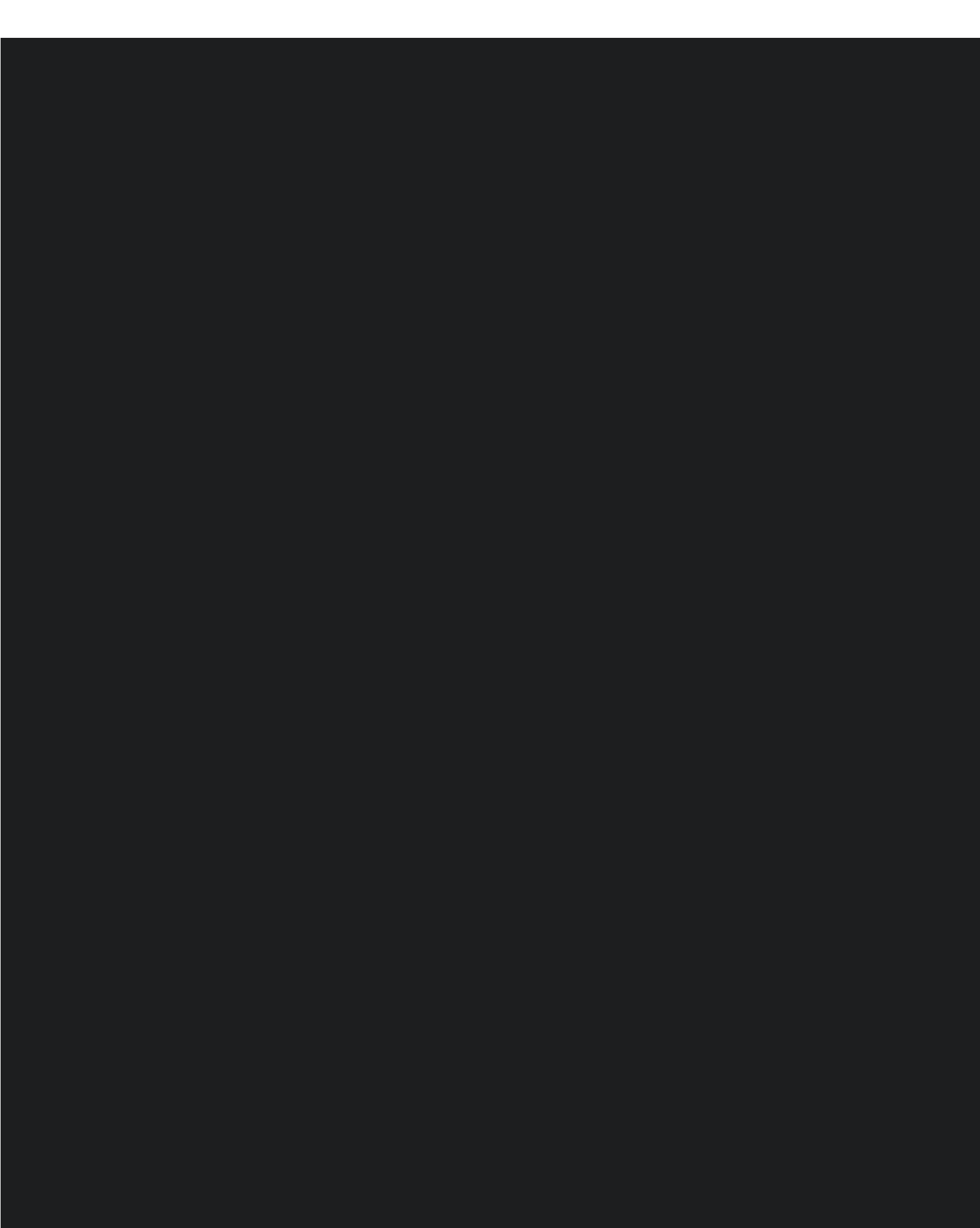












PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

PROJECT NEED, BENEFITS, AND COST-EFFECTIVENESS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
PROJECT NEED, BENEFITS, AND COST-EFFECTIVENESS

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 3**
3 **PROJECT NEED, BENEFITS, AND COST-EFFECTIVENESS**

4 **A. Introduction**

5 The purpose of this chapter is to describe the need for the Helms Pumped
6 Storage Facility (Helms) Uprate Project (Uprate), the benefits that Pacific Gas
7 and Electric Company (PG&E) expect it to provide, and to evaluate the
8 cost-effectiveness of the project relative to expected energy market value
9 streams and relative to other potential opportunities for PG&E to procure
10 comparable energy storage products.

11 **B. Introduction**

12 The Helms Uprate is a cost-effective approach to provide the California
13 Independent System Operator (CAISO)-controlled grid with additional
14 long-duration energy storage. Such long-duration energy storage will become
15 increasingly critical to help integrate the grid's rapidly increasing volumes of
16 intermittent renewable generation, contribute to mitigation of ongoing grid
17 stability challenges, and provide resiliency during periods of peak demand and
18 emergencies.

19 As economic, regulatory, and legislative forces spur a rapid evolution of the
20 California grid, energy storage becomes more important to help maximize the
21 value of the greenhouse gas (GHG)-free, yet intermittent, renewables that are
22 necessary on the path towards decarbonization. While most of the energy
23 storage currently being deployed in California consists of shorter duration
24 storage technologies, like lithium-ion (Li-ion) batteries, the Helms Uprate
25 represents an opportunity to add to PG&E's complementary long-duration
26 storage that can store excess energy for significantly longer periods of time.
27 Planning work done by State agencies over the past several years call for
28 increasing amounts of long-duration storage.

29 The Helms Uprate is a single project that will increase the plant's generation
30 capacity by 150 to 180 megawatts (MW) while also accomplishing the otherwise
31 needed Lifecycle Replacement Work. The Lifecycle Replacement Work is
32 needed to maintain Helm's existing generation and pumping capacity into the
33 middle of the next century. Without the Lifecycle Replacement Work, Helm's

1 capability will degrade to the detriment of all customers.¹ In addition to
2 maintaining Helms as a future resource, the Lifecycle Replacement window
3 provides an opportunity to increase the generation capacity. PG&E's
4 cost-effectiveness analysis shows that the Net Incremental Capacity² included
5 in the Helms Uprate represents a highly cost-effective approach to benefit
6 PG&E's bundled portfolio customers and address broader system-wide needs,
7 as explained in further detail below.

8 This chapter presents the need for and benefits of the Helms Uprate Project.
9 This includes a discussion of recent actions by the California Legislature and
10 State agencies, the Project's fit as part of PG&E's bundled portfolio, and its local
11 area benefits. This is followed by a cost-effectiveness analysis justifying the Net
12 Incremental Capacity of the Uprate. Lastly, the testimony presents the
13 Environmental and Social Justice (ESJ) benefits. This chapter also includes a
14 confidential comparison to other storage projects and the Report of the
15 Independent Evaluator.

16 **C. Project Need**

17 Currently, most energy storage deployed and planned in California is Li-ion
18 technology, a type of rechargeable chemical battery storage that is currently
19 most useful for shorter durations prior to needing to recharge (i.e., often four
20 hours but generally less than eight hours overall). As more intermittent
21 renewable energy generation is added to the grid, the need for longer duration
22 storage will continue to increase to store excess generation during periods of
23 overproduction for use during periods of higher net load when energy is most
24 needed. In response to increasing calls for long-duration storage from state
25 legislators, policymakers and regulators, PG&E identified the Helms Uprate
26 Project as a prime candidate to provide additional long-duration storage capacity
27 while maintaining the capabilities of an important existing resource. Importantly,
28 by combining the Uprate with already-required Lifecycle Replacement Work and
29 the availability of tax credits, described in Chapter 2, the Uprate can be
30 completed at a significantly lower net cost than had previously been possible. In

1 Please see Chapter 2 for a definition of the Lifecycle Replacement Work and a further description of its major components.

2 Please see Chapter 2 for a definition of Net Incremental Capacity.

1 short, these factors present a unique opportunity to meet critical long-duration
2 storage needs in a cost-effective manner.

3 **1. Alignment With Legislation**

4 In addition to meeting identified grid planning and reliability needs, as
5 described below, the Helms Uprate will also advance more general State
6 and California Public Utilities Commission (CPUC or Commission) policy
7 objectives. This section describes the consistency of the Uprate with the
8 Legislature’s general findings regarding the importance of storage and the
9 need for additional energy storage resources.

10 **a. Alignment with Policy Goals of Assembly Bill 1373**

11 Earlier in 2023, the Legislature passed and the Governor signed
12 Assembly Bill (AB) 1373, which allows the Department of Water
13 Resources (DWR) the authority to act as a centralized procurement
14 entity (CPE) until January 1, 2035, requires the CPUC and California
15 Energy Commission (CEC) to assess capacity payments for
16 load-serving entities (LSE) and local publicly owned electric utilities
17 (POUs) that are deficient in meeting their reliability obligations until
18 June 30, 2027, and grants additional CPUC enforcement and potential
19 penalty authority over LSEs’ Integrated Resource Plans (IRP).
20 According to the AB 1373 Assembly Floor Analysis, LSEs having
21 “trouble satisfying the CPUC’s recent electric procurement orders,”
22 necessitated legislation that authorized DWR to “procure additional
23 electrical capacity to meet clean energy and reliability requirements.”³
24 The Assembly’s Analysis repeatedly cites the need for long-duration
25 storage, which the Helms Uprate project will provide and preserve.
26 According to the author of the bill, needed resources include
27 “large-scale storage” that “can better match intermittent resources’
28 profile.”⁴ This intent is echoed in the Governor’s press release issued
29 upon his signing of the bill, in which the Governor states the concern

3 AB 1373 (Garcia, 2023), Assembly Floor Analysis (Sept. 14, 2023), pp. 2-3, available
at:
https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240AB1373
(accessed Dec. 7, 2023).

4 *Id.*, at p. 3.

1 that LSEs “may not buy the clean energy—like offshore wind or
2 long-duration storage—that we need to achieve a 100 percent clean
3 electric grid.”⁵ The value achieved from the Helms Uprate Project
4 clearly supports the specified state-wide need for additional
5 long-duration, large-scale storage. Proactively increasing and
6 maintaining Helms’ generation capacity helps to mitigate the need for
7 the CPE authorized by AB 1373 as a backstop.

8 **b. General Legislative Findings Regarding Storage**

9 The State has similarly moved to expand generation and
10 long-duration storage to support statewide reliability goals and has
11 generally expressed interest for projects that provide these benefits. For
12 example, the State Assembly held its Annual Oversight Hearing of
13 California’s Energy Entities on May 16, 2023, and focused on “Grid
14 Reliability and 2023 Summer Readiness.”⁶ The “Background on
15 Reliability” document that the Assembly provided for the hearing
16 emphasized the benefits of additional system storage, referencing the
17 long-duration storage needs found in CPUC’s IRP analyses and
18 Mid-Term Reliability (MTR) procurement orders, which are discussed
19 further below.⁷

20 In the past few years, the Legislature has undertaken multiple efforts
21 to address reliability and capacity concerns in the State. In 2022, the
22 Legislature passed Senate Bill (SB) 846 (Dodd, 2022), which provided a

5 Office of Governor Gavin Newsom, Governor Newsom and Legislative Leaders Announce Agreement to Fast-Track a Cleaner, More Reliable Grid (Aug. 31, 2023), available at: <https://www.gov.ca.gov/2023/08/31/governor-newsom-and-legislative-leaders-announce-agreement-to-fast-track-a-cleaner-more-reliable-grid/> (access Dec. 7, 2023).

6 California State Assembly, Utilities and Energy: Oversight Hearing, Annual Oversight Hearing of California’s Energy Entities: Focus on Grid Reliability and 2023 Summer Readiness (May 16, 2023), available at: <https://autl.assembly.ca.gov/bill-hearings/informationaloversight-hearings> (accessed Dec. 7, 2023).

7 California State Assembly, Utilities and Energy Committee, Annual Oversight Hearing of California’s Energy Entities: Focus on Grid Reliability and 2023 Summer Readiness, Background Document (May 16, 2023), p. 3, available at: https://autl.assembly.ca.gov/sites/autl.assembly.ca.gov/files/1%20ReliabilityHearing_background.pdf (accessed Dec. 7, 2023).

1 pathway for the extended operations of the Diablo Canyon Power Plant,
2 similarly citing in its bill analyses capacity deficiencies as a cause for the
3 legislation.⁸ Also in 2022, the Legislature passed AB 205
4 (Committee on Budget, 2022) which, among its many provisions,
5 established the Electric Supply Strategic Reliability Reserve Program
6 and Strategic Reliability Reserve, as well as established the Long
7 Duration Energy Storage program to promote non-Li-ion energy storage
8 technologies and projects across California.⁹ While these bills did not
9 specifically call for the Helms Uprate Project, the value provided by the
10 Uprate, as discussed further below, will directly support the goals and
11 intentions specified in the legislation.

12 In 2010, the Legislature enacted AB 2514 regarding energy storage
13 systems and related procurement targets. In enacting that bill, the
14 Legislature made a number of key findings supporting the procurement
15 of additional energy storage across the State, including the following:

- 16 a) Expanding the use of energy storage systems can assist [LSEs
17 and] local POUs in integrating increased amounts of renewable
18 energy resources into the electrical transmission and distribution
19 grid in a manner that minimizes emissions of GHGs;
- 20 b) Additional energy storage systems can optimize the use of the
21 significant additional amounts of variable, intermittent, and off peak
22 electrical generation from wind and solar energy that will be entering
23 the California power mix on an accelerated basis;
- 24 c) Expanded use of energy storage systems can reduce costs to
25 ratepayers by avoiding or deferring the need for new fossil
26 fuel-powered peaking powerplants and avoiding or deferring
27 distribution and transmission system upgrades and expansion of the
28 grid;
- 29 d) Expanded use of energy storage systems will reduce the use of
30 electricity generated from fossil fuels to meet peak load
31 requirements on days with high electricity demand and can avoid or
32 reduce the use of electricity generated by high carbon-emitting
33 electrical generating facilities during those high electricity demand
34 periods. This will have substantial co-benefits from reduced
35 emissions of criteria pollutants;

8 SB 846 (Dodd, 2022), Ch. 239.

9 AB 205 (Committee on Budget, 2022), Ch. 61, Sec. 6.

e) Use of energy storage systems to provide the ancillary services (A/S) otherwise provided by fossil-fueled generating facilities will reduce emissions of carbon dioxide and criteria pollutants; and

f) There are significant barriers to obtaining the benefits of energy storage systems, including inadequate evaluation of the use of energy storage to integrate renewable energy resources into the transmission and distribution grid through long-term electricity resource planning, lack of recognition of technological and marketplace advancements, and inadequate statutory and regulatory support.¹⁰

Although PG&E is currently in compliance with the energy storage procurement requirements set forth in AB 2514, the findings set forth in that legislation continue to support the need to maintain and add energy storage, particularly long-duration energy storage like that provided by the Uprate capable of providing a broader array of critical grid services.

2. Alignment With CEC Policies

In July 2016, the CEC released a Staff Paper titled Bulk Energy Storage in California, which states in the executive summary: “Bulk energy storage, which includes pumped hydroelectric energy storage and other large-scale energy storage methods, is seen as a key resource to help meet the challenges of renewable energy integration onto California’s electric grid.”¹¹ The challenges and potential solutions identified then by the CEC staff remain true today. Specifically, the Staff Paper describes how increasing renewable energy on the electric grid introduces “new challenges aris[ing] to manage these variable resources safely, reliably, and affordably. Challenges include short, steep electricity demand ramps, overgeneration risk, and fewer conventional resources that can provide frequency response.”¹² It then introduces long-duration storage “as one option available to support grid flexibility and reliability” and states that “[i]n some circumstances, energy storage can reduce the cost of renewable resource

¹⁰ AB 2514 (Skinner, 2010), Ch. 469, Sec. 1(f).

¹¹ California Electric Commission, Bulk Energy Storage in California Staff Paper (July 2016), p. 1, available at: <https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2016-006.pdf> (accessed Dec. 7, 2023).

¹² *Id.*, at p. 2 (citation omitted).

1 intermittency and help manage the physical grid constraints that limit high
2 penetration of renewable resources.”¹³ The Helms Uprate Project provides
3 cost-effective additional bulk energy storage while keeping existing bulk
4 energy storage online, which the CEC identified as a key resource to
5 address the challenges of renewable energy integration.

6 **a. Draft 2023 Integrated Energy Policy Report**

7 On October 13, 2023, the CEC released its Draft 2023 Integrated
8 Energy Policy Report (IEPR) (Draft Report), which provides updates on
9 a variety of energy issues confronting California which require action if
10 the State is to meet its climate, energy, air quality and other
11 environmental goals while meeting reliability and controlling costs.¹⁴
12 The Draft Report heavily emphasizes the need for storage, stating that
13 “to achieve 100 percent renewable and zero-carbon electricity by 2045
14 ... storage installation rates need to grow by nearly eightfold,” relative to
15 2020.¹⁵ Besides noting the general need for increased storage, the
16 Draft Report specifically notes the potential for long-duration energy
17 storage, describing the potential for nascent technologies to fill that gap.
18 The need and cost for such nascent technologies—which may require
19 expensive new development of greenfield sites and related transmission
20 and additional research and development—can be partially mitigated by
21 expanding the extant Helms Pumped Storage facility as proposed in this
22 Application.

23 **3. System Need for Long-Duration Storage**

24 To ensure that there are sufficient resources available to meet the
25 State’s GHG reduction goals and grid reliability needs in a cost-effective
26 manner, the Commission in recent years has issued a series of decisions
27 ordering LSEs across the State, including PG&E, to procure historic
28 amounts of GHG-free generation and storage capacity. The trend has been

13 *Id.*, at p. 3.

14 CEC, Draft 2023 IEPR (Nov. 2023), available at:
<https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report> (accessed Dec. 7, 2023).

15 *Id.*, at p. 1.

1 for the Commission to identify increasing amounts of both with each
2 subsequent planning order or rulemaking. The Helms Uprate Project will
3 help to meet the system need for storage capacity – and long-duration
4 storage capacity in particular - clearly identified in years of planning analysis
5 by the Commission and other State agencies. To meet the objectives of
6 these procurement orders, it is vital to maintain existing long-duration
7 storage capacity while adding more, which the Helms Uprate Project does.

8 In 2021, the Commission ordered in Decision (D.) 21-06-035 the
9 procurement of 11,500 MW of new Net Qualifying Capacity (NQC)¹⁶ to
10 come online in the years 2023-2026 from zero-emitting or otherwise
11 Renewable Portfolio Standard-eligible resources to ensure mid-term
12 reliability through the mid-to-late 2020s.¹⁷ At least 1,000 MW of the
13 procurement the Commission ordered in D.21-06-035 must be obtained
14 from long-duration storage resources (defined as “able to deliver at
15 maximum capacity for at least eight hours from a single resource”¹⁸) by
16 2028,¹⁹ with PG&E required to procure 200 MW of that amount.²⁰ The
17 basis for this ordered procurement, in part, was the Reference System Plan
18 (RSP) adopted in D.20-03-028, in which long-duration storage was identified
19 as needed to “help diversify the grid resources and improve reliability and
20 renewables integration.”²¹ Requiring development of long-lead time
21 resources, including long-duration energy storage, is also consistent with the

16 Net qualifying capacity, or “NQC,” is defined as the amount of capacity from each resource type which can be counted towards meeting the Mid-Term Reliability procurement requirements, based on the incremental effective load carrying capacity (“ELCC”) as published by the Commission.

17 See D.21-06-035, p. 94, Ordering Paragraph (OP) 1.

18 D.23-02-040, p. 27.

19 *Id.*, at p. 2 (postponing requirements for procurement of long lead-time resources from D.21-06-035 to 2028).

20 D.21-06-035 indicates the long-lead time (LLT) procurement “will be in two categories: a minimum 1,000 MW of long-duration storage, and a minimum of 1,000 MW of firm resources with zero on-site emissions or, if the resources have emissions, they must otherwise qualify under the RPS eligibility requirements....” (D.21-06-035, p. 35.) Therefore, half of the 2,000 MW LLT procurement requirement must be met by long-duration storage. Table 6 indicates PG&E’s total bundled obligation for the LLT procurement is 400 MW, half of which will need to be met with long-duration storage (i.e., 200 MW). (*Id.*, at p. 26).

21 *Id.*, at p. 88, Finding of Fact 14.

1 adopted IRP objectives to “identify [and develop] a diverse and balanced
2 portfolio of resources....”²²

3 In 2023, the Commission ordered additional mid-term resource
4 procurement with D.23-02-040, including a total of 4,000 MW of new NQC in
5 2026 and 2027, including “non-emitting, storage, and/or renewable
6 resources....”²³ Further, D.23-02-040 ordered “[t]he long lead-time
7 resources required by D.21-06-035 may be brought online by June 1,
8 2028....The extension to June 1, 2028 for long lead-time resources is
9 authorized for all load serving entities (LSE).”²⁴ These two orders together,
10 totaling 15,500 MW of NQC, including the extension of the long-lead time
11 resource requirement to June 1, 2028, are referred to as the MTR
12 procurement.

13 When discussing its order mandating long-lead-time resource
14 procurement, the Commission noted “[l]ongstanding concerns about
15 resource diversity...”²⁵ and observed that “the capacity procured in recent
16 years has been either solar, solar plus storage, or standalone battery
17 storage.”²⁶

18 The Uprate’s incremental capacity will advance the diversification of
19 resources available to meet State needs, consistent with the Commission’s
20 stated concerns. Helms’ existing and proposed incremental generation
21 capacity provides much longer duration storage than from Li-ion batteries
22 most commonly under development today. Helms can generate
23 continuously for more than eight hours.²⁷

24 Helms’ energy storage potential is big. The maximum stored energy
25 under optimal conditions is roughly 115,000 MWh.²⁸ This is the energy

²² Pub. Util. Code Section 454.51(a).

²³ D.23-02-040, p. 87, OP 2.

²⁴ *Ibid.*

²⁵ See Rulemaking (R.) 20-05-003, Administrative Law Judge’s Ruling Seeking Feedback on MTR Analysis and Proposed Procurement Requirements (Feb. 22, 2021), p. 17.

²⁶ *Ibid.*

²⁷ For example, Helms 1 generated for twelve continuous hours from June 25 to June 26, 2023.

²⁸ Maximum water potential at optimal reservoir conditions is the rough equivalent of 96 hours of generation at 1,200 MW, or 115,000 MWh of maximum stored energy.

1 equivalent of about 140 four-hour battery storage facilities, each with a
2 capacity of 200 MW. Additionally, Helms is an open-loop pumped storage
3 hydro facility connected to the Courtright Reservoir. This means that the
4 upper reservoir watershed is naturally recharging the storage potential,
5 providing more energy than closed-loop batteries. The long generation
6 duration, size and flexibility of Helms is particularly beneficial in meeting the
7 load during the late evening and early morning when there are typically
8 fewer resources available.

9 Additionally, pumped storage provides greater emission reduction
10 benefits than 4-hour batteries. For example, based on the CPUC's Clean
11 System Power GHG emissions model, pumped storage provides
12 approximately 50 percent more GHG emissions reduction benefits than
13 4-hour battery storage due to its greater operating flexibility.²⁹

14 Finally, The Helms Pumped Storage Plant helps maintain power system
15 stability by providing voltage control³⁰ and inertia support in response to
16 grid interruptions.

17 The Commission has also acknowledged a system need, though has
18 not yet ordered specific procurement, for long-duration storage elsewhere,
19 including in the Preferred System Plan (PSP) adopted in D.22-02-004. The
20 PSP showed a 2035 system need of 17,648 MW of battery storage and
21 1,000 MW of pumped storage above the baseline capacity.³¹

29 The 50 percent comparative emission reduction advantage for pumped storage is estimated using the CPUC's available 25 million metric tons (MMT) Clean System Power model, comparing results when adding the expected incremental capacity from this Helms proposal to a 4-hour battery storage equivalent.

30 Each of the three units at Helms can provide reactive power (MVAR), which helps in regulating electric grid voltage.

31 See D.22-02-004, p. 193, OP 7. (The Decision adopts "[t]he core portfolio based on the 38 million metric ton greenhouse gas ... target by 2030 described in Section 4 of [the] decision, which includes the 2020 Integrated Energy Policy Report demand forecast utilizing the high electric vehicle assumptions ... as the portfolio for the [PSP] for 2021.") The 2035 capacities associated with PSP can be seen in the Commission's RESOLVE model, Excel workbook "CPUC IRP RESOLVE_Results_Viewer_2021-12-17_FINAL.xlsx", "Dashboard" tab, lines 37-38, available at:

<https://files.cpuc.ca.gov/energy/modeling/2021%20PSP%20RESOLVE%20Package.zip> (accessed Dec. 7, 2023).

1 In 2023, as part of D.23-02-040, the Commission transmitted to the
2 CAISO the Commission-recommended resource portfolios for use as key
3 inputs in its 2023-2024 transmission planning process (TPP), which helps
4 guide long-term CAISO-wide planning. The 2023-2024 TPP base case
5 includes approximately 86 gigawatts (GW) of new resources by 2035, which
6 in 12 years more than doubles the current system nameplate capacity of
7 approximately 75 GW.³² The 2023-2024 TPP base case shows a 2035
8 system need of 28,381 MW of battery storage and 2,000 MW of pumped
9 storage above the baseline capacity.³³

10 Recent work from other State agencies indicates a need for significantly
11 more generation and storage than currently included in the PSP portfolio to
12 meet California's economy-wide climate goals. The California Air
13 Resources Board's (CARB) Scoping Plan shows a need for significant
14 battery and pumped storage additions above the amounts in the PSP and
15 2023-2024 TPP base case, ultimately calling for additions beyond the
16 baseline of 31,980 MW of battery storage and 2,900 MW of pumped storage
17 by 2035 to meet State GHG targets.³⁴

18 What is clear from the above chronology of the State's electric planning
19 efforts is that increasing amounts long-duration storage, including pumped
20 storage, will be needed beyond the 1,000 MW ordered as part of the MTR
21 procurement.

22 Among other objectives, PG&E submits this application to advance
23 these statewide reliability and GHG reduction goals. In particular, PG&E
24 notes that the incremental pumped storage capacity associated with the

Baseline capacity is the capacity that exists or is contracted for at the time of the analysis.

³² See D.23-02-040, p. 47.

³³ D.23-02-040, p. 48, Table 4. The 2023-2024 TPP portfolio contains 1,000 MW more pumped storage capacity than the 2021 PSP because a lower GHG planning targets and a higher load forecast were used in the modeling, driving greater resource build. The Commission noted the rationale for recommending the more aggressive assumptions was transmission planning and construction typically has a longer lead time than generation and storage. See *Id.*, at pp. 47-50.

³⁴ See Energy+Environmental Economics, AB 32 GHG Inventory Sectors Modeling Data Spreadsheet from the 2022 CARB Scoping Plan (Nov. 14, 2022), available at: <https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx> (accessed Dec. 8, 2023).

1 Helms Uprate may meet the long-duration storage MTR procurement
2 requirements issued in D.21-06-035 and modified in D.23-02-040.³⁵ PG&E
3 acknowledges that the Helms Uprate construction timeline is dependent
4 upon regulatory approval and ongoing engineering review, and may be
5 subject to project delays. Nevertheless, should the Helms Uprate not be
6 completed in time to meet PG&E's MTR procurement obligations, the
7 additional pumped storage capacity remains within the spirit of this identified
8 need and will provide a backstop in the event other resources procured to
9 meet that requirement do not come online, or in the event that deadline is
10 moved back.

11 As noted above, the Commission and other State agencies have
12 identified a need for long-duration storage, including pumped storage,
13 beyond the MTR ordered procurement. Recently, the CPUC issued a ruling
14 in Rulemaking 20-05-003 which, among other things, recommends a PSP to
15 be used, "to give direction to [LSE] regarding their procurement activities
16 and for their next round of individual integrated resource plans (IRPS)."³⁶
17 The recommended PSP achieves compliance with the MTR orders and
18 shows needed long-duration storage nameplate capacity increasing from
19 1,800 MW in 2028 to 3,800 MW in 2035, highlighting an additional 2,000
20 MW to be procured after the 2028 MTR online date.³⁷

21 In the event work on the Helms Uprate is not completed in time to meet
22 PG&E's initial MTR procurement obligations, PG&E anticipates it should be
23 online in time to meet longer term Commission planning requirements,

³⁵ As noted above, D.23-02-040 automatically postponed requirements for procurement of long lead-time resources from D.21-06-035 to 2028. See D.23-02-040, p. 2.

In May 2023, California Energy Storage Alliance and the Western Power Trading Forum filed a Petition for Modification of D.21-06-035 and D.23-02-040 requesting that the required online date for long-lead time resource procurement including the long-duration storage be delayed from June 1, 2028, to June 1, 2031.

³⁶ R.20-05-003, Administrative Law Judge's Ruling Seeking Comment on Proposed 2023 Preferred System Plan and Transmission Planning Process Portfolios (Oct. 5, 2023), p. 3.

³⁷ R.20-05-003, pp. 20-21, Table 2. The long-duration storage amounts include three resource categories: (1) 8-hr Battery, (2) Pumped Hydro Storage, and (3) Long Duration Storage.

1 including any future procurement orders that are issued to meet those
2 planning needs.

3 **4. PG&E's Bundled Portfolio Need**

4 The Helms Uprate Project is needed to satisfy the clean energy and
5 reliability requirements for PG&E's bundled customers. The Uprate's
6 estimated addition of 150 to 180 MW of new system capacity is supported
7 by the bundled portfolio's energy storage need identified in PG&E's 2022
8 Integrated Resource Plan (IRP).³⁸

9 PG&E has a 200 MW MTR procurement requirement for long-duration
10 storage resources. Depending on Commission's action on the Petition for
11 Modification (Petition) on long lead-time resource procurement³⁹ and the
12 Helms Uprate construction timeline, the Helms Uprate Project may satisfy a
13 substantive portion of the 200 MW requirement for PG&E's bundled
14 customers.

15 The Petition, filed by the California energy Alliance and the Western
16 Power Trading Forum, discusses the barriers in procuring long lead-time
17 resources. The Petition explains, "Challenges to new resource development
18 are well-documented and discussed across all state agencies that have a
19 role in planning, procuring, operating, and regulating the electric sector.
20 These challenges include but are not limited to supply chain constraints,
21 trade-related uncertainty or moratoriums, interconnection, and network
22 upgrade delays, permitting delays, and an inflationary macroeconomic
23 environment that has increased the cost of capital, labor costs, and
24 equipment/commodity costs."⁴⁰ "Overall, a challenging macroeconomic
25 environment adds to the contracting and development difficulties of LDES
26 [long-duration energy storage] resources, which were categorized within the

³⁸ R.20-05-003, PG&E 2022 IRP (Nov. 1, 2022) (2022 IRP Report), available at: <https://www.pge.com/content/dam/pge/docs/about/doing-business-with-pge/2022-PGE-Integrated-Resource-Plan.pdf> (accessed Dec. 8, 2023).

³⁹ In May 2023, California Energy Storage Alliance and the Western Power Trading Forum filed a Petition for Modification of D.21-06-035 and D.23-02-040 requesting that the required online date for long-lead time resource procurement including the long-duration storage be delayed from June 1, 2028, to June 1, 2031.

⁴⁰ R.20-05-003, Petition for Modification of Decisions 23-02-040 and 21-06-035 of the California Energy Storage Alliance and the Western Power trading Forum to Address Long Lead-time Resource Compliance Deadlines (May 30, 2023), p. 10.

1 LLT resource category for a reason. That is, having seen little or no new
2 resource development for technologies other than solar, wind, and
3 lithium-ion battery storage, the Commission acknowledged that ‘the
4 commercial interest shown thus far in diverse and LLT resources that can be
5 online by 2026 may be limited.’⁴¹ The barriers and difficulties discussed in
6 the Petition highlights the Uprate’s unique opportunity to add cost-effective
7 long-duration storage.

8 In the event the work on the Helms Uprate is not completed in time to
9 meet PG&E’s initial MTR procurement obligations, PG&E forecasts, based
10 on its 2022 IRP, that the Uprate capacity will be needed to meet subsequent
11 bundled customer clean energy needs.

12 In its 2022 IRP PG&E studied three scenarios.⁴² The three scenarios
13 identified a range of incremental procurement needed by 2035 beyond
14 PG&E’s baseline resources, which includes the Helms’ existing capacity.
15 Total new resource additions, both generation and storage, ranged from
16 5,500 to 11,400 MW.⁴³ Storage additions ranged from 1,100 to 4,800
17 MW.⁴⁴ Unsurprisingly, the range of new resources needed to serve
18 PG&E’s bundled load in 2035 significantly exceeds PG&E’s MTR
19 procurement requirement of 3,077 MW⁴⁵. The tables from PG&E’s 2022

⁴¹ *Id.*, at pp. 12-13.

⁴² In its 2022 IRP Report, PG&E prepared two Conforming and one Alternative Portfolios:

- 1) Conforming Portfolio for Scenario 1: 30 MMT GHG, Conforming Load;
- 2) Conforming Portfolio for Scenario 2: 25 MMT GHG, Conforming Load; and
- 3) Alternative Portfolio for Scenario 3: 30 MMT GHG, Additional Transportation Electrification (ATE) Load.

The two conforming scenarios were constructed using the CEC’s 2021 IEPR “Mid Load” forecast. The Alternative Scenario used the ATE 2021 IEPR load forecast produced jointly by the CEC, CPUC and the CAISO. The ATE incorporated more aggressive assumptions about the pace of the electrification of the transportation sector than what is reflected the 2021 IEPR Mid Load forecast. The ATE best aligns with CARB’s electric sector GHG emissions targets as well as PG&E’s internal load forecast.

⁴³ PG&E 2022 IRP Report, pp. 34-36, Tables 7, 8 and 9.

⁴⁴ *Ibid.*

⁴⁵ The 3,077 MW is the sum of PG&E’s ordered procurement from D.21-06-035, p. 56, Table 6, Individual LSE Procurement Minimum Obligations (in September NQC MW) and D.23-02-040, p. 31, Table 3: Allocation of Procurement Responsibility by LSE.

1 IRP detailing the additional procurement required for the three scenarios is
2 Attachment A to this chapter.

3 The Helms Uprate capacity is approximately 5 to 15 percent of the 2035
4 storage additions' range. Although it represents a small portion of PG&E's
5 2035 additions, the Uprate will be an important resource in PG&E's future
6 bundled portfolio. Based on the State's increasingly ambitious
7 GHG-reduction and electrification goals,⁴⁶ it is unlikely that the need for
8 additional long-duration storage resources identified in PG&E's forthcoming
9 2024 IRP will decrease.

10 It is important to note that in PG&E's 2022 IRP, the optimization chose
11 4-hour batteries to meet the incremental storage need for all three
12 scenarios. This was because the assumed levelized costs for greenfield
13 pumped storage proved to be prohibitive. However, because of the unique
14 circumstance in which the Helms existing facility will be uprated, pumped
15 storage from the Helms Uprate becomes a more attractive alternative to
16 4-hour battery technology. The net market value of the Uprate is discussed
17 in Section C below. A comparison to other storage projects is provided in
18 Confidential Attachment B to this chapter.

⁴⁶ See, for example, California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality (Nov. 16, 2022), p. 116, "Under the Scoping Plan Scenario, in 2030 California emissions are anticipated to be 48% below 1990 levels. This represents an acceleration of the current SB 32 target of a 40% reduction below 1990 levels.", available at: <https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf> (accessed Dec. 8, 2023). See also D.23-02-040, pp. 2 and 6, which orders a total of 4,000 MW of NQC for, among other reasons, an "updated load forecasting from the California Energy Commission ... that suggests that electricity demand is increasing and will continue to increase compared to when D.21-06-035 was adopted," due in part to "increasing penetration of electric vehicles, increasing penetration of air conditioning, [and] electrification of buildings...." See also, R.20-05-003, Administrative Law Judge's Ruling Seeking Comment on Proposed 2023 Preferred System Plan and Transmission Planning Process Portfolios (Oct. 5, 2023), pp.19-23, which Commission Staff recommend "selecting 25 MMT as the GHG target in 2035." A decrease from the 30 MMT target in 2035 associated with the 2021 PSP Portfolio. Available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K522/520522241.PDF> (accessed Dec. 8, 2023).

5. Greater Fresno Local Capacity Area Need

Helms is located in the Greater Fresno Local Capacity Area (Local Area).⁴⁷ Based on preliminary engineering studies, PG&E expects that the Helms Uprate Project will increase the interconnected generation capacity in the Local Area by 129 to 156 MW.⁴⁸ The Local Area capacity requirement is expected to grow by 700 MW between 2024 and 2028.⁴⁹ Although the total NQC of resources in the Local Area is currently greater than the local capacity requirement, it is desirable, especially given the expected local load growth, to maintain existing and add incremental GHG-free capacity in the Fresno Local Area. Additionally, the incremental Uprate capacity increases grid resilience for a 1-in-10 load event,⁵⁰ which may result in local load that is approximately 116 percent of the NQC of local resources.⁵¹

⁴⁷ According to the CAISO's 2028 Locational Capacity Technical Final Report and Study Results, the Greater Fresno Local Capacity Area in 2028 is forecasted to have a local capacity requirement of 2,728 MW and a total NQC for local area resources of 3,127 MW. The Study also identified a peak load (1-in-10) need of 3,637 MW. CAISO, 2028 Local Capacity Technical Study, Final Report and Study Results (Apr. 28, 2023), p. 22, Table 3.1-1, available at: <http://www.caiso.com/InitiativeDocuments/Final-2028-Long-Term-Local-Capacity-Technical-Report.pdf> (accessed Dec. 8, 2023).

⁴⁸ The Uprate generation capacity increase at the point of interconnection is estimated at 129-156 MW. The Uprate nameplate capacity increase is estimated at 150-180 MW. The capacity increase at the point of interconnection is less than the nameplate capacity increase due to transformer and transmission line losses between the Helms' generators and the point of interconnection at Gregg Substation in Fresno, CA, approximately 60 miles from Helms. The lower capacity values at the point of interconnection are used in forecasting market revenues since this is capacity that can be delivered to the grid.

⁴⁹ CAISO, 2024 Local Capacity Technical Study, Draft Report and Study Results (Apr. 5, 2023), available at: <http://www.caiso.com/InitiativeDocuments/Draft-2024-Local-Capacity-Technical-Report.pdf> (accessed Dec. 8, 2023).

⁵⁰ A "1-in-10 load event" refers to systems having enough resources to experience no more than one outage every 10 years due to insufficient capacity. For more information, see CAISO, 2023 Summer Loads and Resource Assessment (May 15, 2023) available at: <http://www.caiso.com/Documents/2023-Summer-Loads-and-Resources-Assessment.pdf> (accessed Dec. 8, 2023).

⁵¹ CAISO's 2028 Local Capacity Technical Final Report and Study, *supra*, p. 22, Table 3.1-1, estimates that in 2028, the Greater Fresno Local Area will have a peak load (1-in-10) of 3,637 MW and Total NQC Local Area Resources of 3,127 MW. 3,637 MW divided by 3,127 MW equals 116 percent.

1 Finally, the incremental Uprate capacity may result in lower dispatch and
2 emissions from the fossil units in the Local Area. CAISO estimates that in
3 2028, there will be 51 emitting units with 1,370 MW of NQC in the Local
4 Area.⁵² This represents approximately 44 percent of the forecasted 2028
5 Local Area resource capacity. The incremental Uprate capacity provides
6 additional non-emitting generation options to meet the Local Area capacity
7 requirement, and the long-duration storage dispatch may result in less
8 generation from local emitting resources during periods of constrained
9 transmission. Further, less generation from local emitting resources aligns
10 with California's objective to reduce reliance on nonpreferred resources⁵³ in
11 local areas as evidenced by SB 887 which requires the CPUC to provide
12 portfolios to the CAISO which are "expected to substantially reduce, no later
13 than 2035, the need to rely on nonpreferred resources in local capacity
14 areas."⁵⁴

15 **D. Cost Effectiveness**

16 **1. Helms Uprate Net Market Value**

17 The purpose of the Net Market Value analysis is to compare the
18 incremental benefits to the incremental costs of the Uprate, providing a net
19 market value of the project. Both the benefits and the costs are incremental
20 to the Lifecycle Replacement Work.

21 The tables below show the Net Market Value (NMV) of the Incremental
22 Capacity for the Helms Uprate Project. The first table shows the NMV
23 expressed in net present value in 2024. The second table shows NMV in
24 levelized dollars per kilowatt year (kW-year) to assist in the comparison to
25 other projects discussed further in Section C.2, below.

⁵² CAISO, 2024 and 2028 Local Capacity Technical Studies (Apr. 28, 2022), Attachment A, Tab "Physical Res. 2028 LCR", Column G, available at: <https://www.caiso.com/InitiativeDocuments/Attachment-A-List-of-Physical-Resources-Accounted-for-in-the-2024-and-2028-Local-Capacity-Technical-Studies.xls> (accessed Dec. 8, 2023).

⁵³ Pub. Util. Code Section 454.57(i)(2) defines "nonpreferred resources" as "electrical generation resources that are not renewable energy resources or zero-carbon resources pursuant to Section 454.53."

⁵⁴ Pub. Util. Code Section 454.57 (e)(4)(A).

The higher incremental capacity scenario, Scenario 1, is based on 156 MW and 78 MW of increased capacity for generation and pumping at the interconnection point, respectively. The lower incremental capacity scenario, Scenario 2, is based on 129 MW and 0 MW of increased capacity for generation and pumping at the interconnection point, respectively. These scenarios are meant to provide reasonable “book ends” for the potential outcome of the project based on final engineering given the preliminary nature of the current design studies. Both scenarios have the same estimated project cost and revenue requirement. The revenue requirement is shown as a negative value indicating a cost in the NMV analysis. The market revenue and resource adequacy value are shown as positive values indicating benefits.

Both capacity scenarios have a positive NMV. Scenario 1 and Scenario 2 have an NMV, including a portfolio fit adjustment, of \$96.5 and \$15.1 **million** (2024 dollars), respectively. The levelized NMV per kW-year for Scenario 1 and Scenario 2 are \$67.20 and \$12.70, respectively.

The market revenue is forecasted using PG&E’s Storage Valuation Model and PG&E’s internally developed price forecasts. This is same model and revenue forecasting approach used in PG&E’s MTR Phase III offer valuation process. The revenue forecasts of the two scenarios are different reflecting the different capacities.

**TABLE 3-1
HELMS UPRATE PROJECT – INCREMENTAL CAPACITY
NET PRESENT VALUE
(MILLIONS OF DOLLARS)**

Line No.	Scenarios	Revenue Requirement	Market Revenue		Resource Adequacy Value	Network Upgrade Cost	NMV Before Adjustment	Portfolio Fit Adjustment	NMV with Portfolio Adjustment
			Net Energy	Ancillary Services					
1	Scenario 1: Higher Incremental Capacity	\$(92.6)	\$82.5	\$7.6	\$103.6	\$(9.7)	\$91.5	\$5.0	\$96.5
2	Scenario 2: Lower Incremental Capacity	\$(92.6)	\$20.5	\$5.4	\$85.7	\$(8.0)	\$11.0	\$4.1	\$15.1

Notes: The net present value discounts future project revenue requirements and revenues to June 1, 2024, at PG&E’s after-tax weighted average cost of capital (WACC) of 6.70 percent.

Table may not add due to rounding.

TABLE 3-2
HELMS UPRATE PROJECT – INCREMENTAL CAPACITY
LEVELIZED DOLLARS PER KW-YEAR

Line No.	Scenarios	Revenue Requirement	Market Revenue		Resource Adequacy Value	Network Upgrade Cost	NMV Before Adjustment	Portfolio Fit Adjustment	NMV with Portfolio Adjustment
			Net Energy	Ancillary Services					
1	Scenario 1: Higher Incremental Capacity	\$(64.50)	\$57.50	\$5.30	\$72.10	\$(6.70)	\$63.70	\$3.50	\$67.20
2	Scenario 2: Lower Incremental Capacity	\$(78.00)	\$17.30	\$4.50	\$72.10	\$(6.70)	\$9.30	\$3.50	\$12.70

Note: The units in this table are levelized cost per kW-year of incremental capacity. The levelized revenue requirement per kW-year is higher in Scenario 2 as compared to Scenario 1. Although the project cost is the same for both scenarios, Scenario 2 has lower incremental capacity yielding a higher levelized cost.

Table may not add due to rounding.

1 Details of the NMV calculation are provided below.

2. Comparison to Other Storage Projects

3 To assist in its evaluation of the cost-effectiveness of this project, PG&E
4 bid evaluation experts, who are subject to a Code of Conduct to prevent
5 sharing of third-party information with PG&E's Uprate development team,
6 compared this project to offers currently shortlisted in its MTR Phase III
7 procurement. Specifically, PG&E compared this project to those projects on
8 its shortlist, still under negotiation, that PG&E believes are likely candidates
9 for execution. This is consistent with PG&E's past practices to compare
10 projects that originate outside a specified request for offers (RFO) to offers
11 received in a relevant RFO that PG&E is currently evaluating. Based on this
12 assessment, this project compares very well to the other projects PG&E is
13 currently considering. As the information on the comparator group includes
14 non-public information on both potential counterparties and the economics
15 of their proposed transactions, this information is market-sensitive and is
16 provided in Confidential Attachment B to this chapter.

3. Net Market Value Calculation

The NMV is calculated for the Incremental Capacity of the Uprate. The net amount is an aggregation of the forecasted incremental revenue less the forecasted incremental cost (i.e., its revenue requirements). The analysis considers net energy and ancillary market revenue paid by the CAISO and resource adequacy value. The NMV is the sum of the negative revenue requirement (i.e., a cost) and the positive net energy and A/S market revenue and resource adequacy value.

A Portfolio Fit Adjustment is included in the analysis. The Adjustment in this analysis mirrors the Adjustment applied in PG&E's MTR Phase III offer valuation process. It adjusts the project value for how well the incremental energy fits within the hourly profile of PG&E's bundled portfolio. The Adjustment can be positive or negative to reflect the degree of fit with the portfolio's needs. For the Helms Uprate, the Adjustment is positive as the plant is dispatchable and can produce energy in hours when needed.

4. Net Incremental Capacity Cost

The forecasted Net Incremental Capacity Cost used for the revenue requirement calculation is \$26.8 million.⁵⁵ The forecasted Uprate Cost is \$462.2 million. Subtracting the forecasted 30 percent federal Investment tax credit (ITC) of \$135.5 million, the Uprate Cost is reduced to \$326.7 million. The Net Incremental Capacity Cost is calculated as the difference between the Uprate Cost less the ITC (\$326.7 million) and the Lifecycle Replacement Cost (\$299.9 million). For purposes of calculating the NMV of the Helms Uprate Incremental Capacity, it is appropriate to use the forecasted Net Incremental Capacity Cost because in the absence of the Uprate, the Lifecycle Replacement Work would need to be done in any case without any Incremental Capacity or ITC benefit.

5. Revenue Requirement Calculation

The revenue requirement recovers the forecasted Net Incremental Capacity Cost through a return on rate base and depreciation of the asset.

⁵⁵ The costs used in the calculation of the Net Incremental Capacity Cost are escalated nominal-year costs with a 50 percent cost contingency, as further described in Chapter 2.

1 It also recovers applicable income taxes associated with the return on rate
2 base and reflects an amortization of the forecasted ITC. Finally, the
3 revenue requirement recovers uncollectible and franchise fees.

4 The rate of return on rate base is PG&E's before-tax weighed average
5 cost of capital (WACC) of 7.28 percent. The forecasted rate base is
6 calculated using the utility plant amount for the Helms Uprate less
7 accumulated depreciation, adjustments for deferred taxes, and other rate
8 base offsets.

9 Depreciation is included in the revenue requirement calculation as both
10 a depreciation expense and a reduction in rate base through accumulated
11 depreciation. The depreciation expense forecast is calculated on a
12 straight-line, remaining-life method.⁵⁶ The forecasted revenue requirement
13 also includes capitalization of Allowance for Funds Used During
14 Construction (AFUDC). The AFUDC amount is the product of the average
15 Construction Work-in-Progress balance and PG&E's before-tax WACC
16 reflecting the company's recorded capitalization and CPUC authorized rates
17 of return.

18 Additional detail on the revenue requirement calculations is provided in
19 Chapter 4.

20 **a. Federal Investment Tax Credit**

21 The revenue requirements calculation includes a 30 percent federal
22 ITC for all ITC-eligible capital costs. PG&E anticipates all of the Uprate
23 Cost, excluding the forecasted Interconnection Customer's
24 Interconnection Facilities⁵⁷ cost of \$12.2 million, will qualify for the ITC
25 due to the project's capacity increase. The total ITC is forecasted as

⁵⁶ Method is in accordance with the Commission's Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals.

⁵⁷ The CAISO tariff defines Interconnection Customer's Interconnection Facilities as follows: "All facilities and equipment, as identified in Appendix A of the Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the CAISO Controlled Grid. Interconnection Customer's Interconnection Facilities are sole use facilities." CAISO Tariff, App. A.

1 \$135.5 million. Additional detail on the ITC calculation is provided in
2 Chapter 4.

3 **b. Income and Property Taxes**

4 The forecasted revenue requirements include the recovery of
5 associated expenses for federal income tax, California corporation
6 franchise tax (or state income tax), and property tax.

7 PG&E follows federal modified accelerated cost recovery system
8 and asset depreciation range guidelines. Federal income tax expense
9 forecast is based on the currently effective corporate income tax rate
10 (21 percent) and forecasted federal taxable income. Likewise, current
11 state income tax expense is the product of the statutory rate
12 (8.84 percent) and the forecasted state taxable income.

13 Deferred income tax is calculated as the difference between book
14 and federal tax deductions multiplied by the federal tax rate and is
15 included as an adjustment to current federal tax expense and a credit to
16 rate base.

17 State income taxes are calculated using flow-through treatment.
18 With a flow-through treatment, customers receive an immediate benefit
19 from use of accelerated state tax deductions; there is no deferred state
20 taxes and therefore, no associated deduction to rate base.

21 Property tax is calculated as the product of the beginning-of-year net
22 book value (i.e., plant account less accumulated book depreciation) and
23 the property tax rate of approximately 1.47 percent.

24 Additional detail on the tax calculations is provided in Chapter 4.

25 **c. Franchise and Uncollectible Fees**

26 As is standard practice, the revenue requirements are adjusted to
27 include recovery of franchise and uncollectible fees. The revenue
28 requirements are multiplied by a franchise fee factor (0.766 percent) and
29 an uncollectible fee factor (0.317 percent).

30 **6. Revenue Calculation**

31 Project revenues are calculated using PG&E's Storage Valuation Model
32 (Model). Thirty-eight years of forecasted revenues are included in the
33 valuation, aligning with the 38-year composite book life of the Helms' assets.

PG&E's internal hourly energy and A/S price forecasts are used as inputs in the Model.⁵⁸ The Model and PG&E's internal price forecasts have also been used in PG&E's MTR Phase III offer valuation process.

Three revenue value streams are included in the NMV analysis: (1) net energy; (2) A/S; and (3) resource adequacy. For revenue modeling simplicity, PG&E assumes an aggregated Uprate online date of January 1, 2031.⁵⁹ For all three revenue streams, PG&E assumes a 77 percent availability factor to account for outages. This factor was derived from five years of historical availability, from 2018 to 2022.

a. Net Energy Revenue

The Model calculates the Energy Gross Margin which is the projected energy revenue minus the variable cost associated with the energy dispatch schedule. The Model calculates the dispatch schedule of the facility using a deterministic optimization. The objective of this deterministic optimization is to maximize the energy gross margin while meeting operating constraints based on hourly forecasted energy prices at the Helms' location.

The quantity of energy delivery for each hour is determined by PG&E's energy-only optimization algorithm. The energy-only optimization algorithm solves for the energy delivery (both charging and discharging)⁶⁰ schedules that maximize the sum of net energy revenue

⁵⁸ PG&E's internal energy price forecasts are developed using a four-step process. First, historical data are used to develop a relationship between the prices and key price drivers. Drivers include system load, generation resources by technology type, natural gas prices, and GHG prices. Second, PG&E develops forecasts of the key price drivers. The forecasts of key drivers are based in part on fundamental modeling of future system load and resources. Third, PG&E creates hourly price forecasts by applying the relationships derived in the first step with the forecasts developed in the second step. Fourth, near-term adjustments are made to the prices to reflect available near-term market data.

A similar process is used to create PG&E's internal A/S price forecasts. Key drivers for A/S prices include hourly price level and shape, seasonality, and hydroelectric generating conditions. Prices are adjusted to account for a forecasted increase in storage.

⁵⁹ Forecasted Uprate online dates for the three units are end-of-year 2029, 2030 and 2031.

⁶⁰ The net energy value includes both energy revenue when the units generate and energy expense when the units are pumping.

1 minus variable costs reflecting the operating constraints of the market
2 bids. The optimization algorithm considers variable costs, such as
3 variable operations and maintenance costs and start-up costs. The
4 optimization algorithm also considers the operating parameters and
5 constraints, such as minimum run time, minimum down time, minimum
6 and maximum operating MW when charging and discharging, and
7 reservoir constraints including efficiency loss.

8 Although the Helms facility has three units, the modeling assumed
9 only two units can pump simultaneously to reflect historical operation.

10 **b. Ancillary Services Revenue**

11 A/S revenue is calculated based as the incremental value that A/S
12 capability provides in addition to Energy Gross Margin. This is
13 calculated as the *difference* between two Model runs: (1) Spot Gross
14 Margin run and (2) Energy Gross Margin run. The Spot Gross Margin is
15 the revenue minus variable costs when providing both A/S and energy.
16 Energy Gross Margin is revenue minus variable costs when providing
17 energy only and is used to calculate the net energy revenue.

18 The Spot Gross Margin run co-optimizes energy and A/S (i.e., spin,
19 regulation up, and regulation down) to maximize total energy and A/S
20 revenues minus variable costs reflecting the operating constraints of the
21 market bids. The approach is like the Model's energy-only optimization
22 algorithm.

23 Additional operational constraints are enforced in the Spot Gross
24 Margin run. The sum of energy and upward A/S (i.e., spin and
25 regulation up) schedules in the discharge mode are limited by: (1) the
26 amount of energy available to discharge and (2) the maximum discharge
27 power. The sum of energy and downward A/S (i.e., regulation down)
28 schedules in the charge mode are limited by: (1) the amount of capacity
29 available to charge and (2) the maximum charge power. The energy
30 balance constraints at each hour consider the efficiency losses from
31 charging and discharging for providing energy and A/S.

c. Resource Adequacy Value

RA value (also known as capacity value) is calculated for all months during the 38-year asset life. The monthly RA value is computed as the sum of two components: (1) local RA value, which also includes system value; and (2) flexible RA value. Monthly local RA value is calculated as the incremental generating capacity⁶¹ multiplied by the forecasted effective load-carrying capability factor and the forecasted local RA price. Monthly flexible RA value is calculated as the incremental generating capacity multiplied by the forecasted effective flexible capacity factor and the forecasted flexible RA price. PG&E's monthly internal RA price forecasts⁶² are used in the RA value calculations.

7. Network Upgrade Cost

As discussed in Chapter 2, PG&E submitted an Interconnection Study request to CAISO for the Helms Uprate Project in March 2023. The CAISO has included the Helms Uprate application in its Cluster 15 Study. PG&E anticipates it will be several years before the Cluster 15 Study is completed and network upgrade cost estimates for the Uprate, if any, are known. Network upgrade costs include all facilities necessary to: (a) reinforce the transmission system after the point where a project's electricity first interconnects with and enters the utility's transmission grid; and (b) transmit or deliver the full amount of generation from the project. These costs are recovered from customers through FERC-approved transmission rates.

Since the network upgrade costs are unknown, PG&E has included a cost placeholder. The placeholder cost is \$101,549 per megawatt of incremental generation energy.⁶³ For the 156 MW generation capacity

⁶¹ The incremental generating capacity is the forecasted capacity at the interconnection point. For Scenario 1 the incremental generating capacity is 156 MW. For Scenario 2 the incremental capacity is 129 MW.

⁶² PG&E's internal RA (system, local and flex) price forecasts are derived using market data (e.g., broker quotes, PG&E transactions, and CPUC published data) for the near term and a transition to a long-term average over time.

⁶³ The network upgrade cost placeholder is based on the CAISO's maximum reliability network upgrade (RNU) reimbursement of \$85,430 per MW of generating capacity for projects with a commercial online date of July 1, 2023 to June 30, 2024, available at <https://www.caiso.com/Documents/CurrentReliabilityNetworkUpgradeReimbursementMaximum.pdf> (accessed Dec. 15, 2023).

1 increase scenario, the network upgrade cost placeholder is \$15.8 million.
2 For the 129 MW increase scenario, the network upgrade cost placeholder is
3 \$13.1 million. In the NMV analysis, PG&E uses a conservative and
4 simplifying assumption that the network upgrade cost recovery occurs in
5 2032, the year following the commercial online date of the final unit.

6 PG&E proposes to submit a Tier 1 Advice Letter to inform the
7 Commission and stakeholders of the full scope of the Phase 2
8 Interconnection Study results, including those for reimbursable network
9 upgrades, once that study is complete.

10 **E. Environmental and Social Justice Benefits**

11 PG&E strives to incorporate ESJ considerations in its investment
12 planning to provide more sustainable, inclusive, and equitable customer
13 energy solutions. ESJ communities consist of disadvantaged communities,
14 low-income communities, and historically marginalized racial and ethnic
15 communities who that have been disproportionately impacted by

PG&E escalated this cost at 2.5 percent per year to develop a maximum RNU reimbursement amount of \$101,549 per MW for the Helms Uprate aggregated online date of Jan. 1, 2031.

1 environmental hazards.⁶⁴ PG&E's ESJ commitments are memorialized in
2 its Environmental and Social Justice Policy,⁶⁵ under which PG&E:

- 3 • Takes responsibility for our actions and operations – past, present, and
4 future;
- 5 • Complies fully with the letter and spirit of all applicable ESJ laws and
6 regulations;
- 7 • Actively seeks community input and use data-driven tools to better
8 understand potential cumulative impacts of PG&E business decisions
9 and to prioritize our actions to help support sustainable communities;

64 According to the CPUC ESJ Action Plan, Version 2.0 (Apr. 7, 2022) (CPUC ESJ Action Plan), p. 2, “Environmental and Social Justice Communities” or “ESJ Communities” are identified as those where residents are:

- Predominantly communities of color or low-income;
- Underrepresented in the policy setting or decision-making process;
- Subject to a disproportionate impact from one or more environmental hazards; and
- Likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities.
- These communities may also include:
- Disadvantaged Communities (defined pursuant to CalEnviroScreen 4.0 as census tracts that score in the top 25 percent of CalEnviroScreen 4.0, those that score within the highest 5 percent of CalEnviroScreen 4.0's Pollution Burden but do not receive an overall CalEnviroScreen score, census tracts identified as Disadvantaged Communities in CalEnviroScreen 3.0, and areas under the control of federally recognized Tribes).
- All Tribal lands.
- Low-income households (defined as household incomes below 80 percent of the area median income); and
- Low-income census tracts (defined as census tracts where aggregated household incomes are less than 80 percent of area or state median income).

65 PG&E Environmental and Social Justice Policy, available at: https://www.pgecorp.com/assets/pgecorp/localized/en/sustainability/corporate-responsibility-sustainability/reports/2023/prosperity/energy-affordability-equity/pge_ej_policy.pdf (accessed Dec. 8, 2023).

- 1 • Incorporates ESJ considerations into our operations and energy delivery
- 2 and maximizes opportunities for small and diverse business in PG&E's
- 3 supply chain;
- 4 • Considers ESJ impacts in our policy engagement to create opportunities
- 5 for and minimize adverse effects on ESJ communities;
- 6 • Educates our coworkers about our ESJ Policy and how to operationalize
- 7 the policy in their work practices;
- 8 • Maintains open communication and seek opportunities to partner with
- 9 our stakeholders on ESJ concerns;
- 10 • Strengthens relationships with the Native American tribal governments
- 11 and communities we serve and develop partnerships to better address
- 12 their environmental concerns; and
- 13 • Conducts our business in a manner that respects the human rights of all
- 14 individuals, as outlined in our Human Rights Policy.⁶⁶

15 The Commission has also adopted its own ESJ Action Plan. The Helms
16 Uprate Project helps in meeting two of the goals in the Commission's ESJ
17 Action Plan 2.0.⁶⁷

18 First, the Uprate makes progress on Goal 2: Increase Investment in
19 Clean Energy Resources to Benefit ESJ Communities, Especially to
20 Improve Local Air Quality and Public Health.⁶⁸ The Uprate's increased
21 capacity and reliability will benefit not only the entire electric system, but, as
22 a non-emitting resource, may particularly benefit the Greater Fresno Local
23 Capacity Area by lowering local area air pollutants as explained in Section
24 B.5, above. While the Helms facility itself is not located in an ESJ
25 community, the City of Fresno, home to many ESJ communities, is the most
26 proximate population center.

⁶⁶ PG&E Human Rights Policy, available at:
https://www.pgecorp.com/assets/pgecorp/localized/en/sustainability/corporate-responsibility-sustainability/reports/2023/people/diversity/PGE_Human_Rights_Policy.pdf
(accessed Dec. 8, 2023).

⁶⁷ CPUC ESJ Action Plan, *supra*, available at:
<https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/key-issues/esj/esj-action-plan-v2jw.pdf> (accessed Dec. 8, 2023).

⁶⁸ CPUC ESJ Action Plan, *supra*, p. 5.

1 Second, the Uprate could advance Goal 7: Promote High Road Career
2 Paths and Economic Opportunity for Residents of ESJ Communities.⁶⁹
3 PG&E's plan to uprate and maintain the Helms Pumped Storage Project will
4 provide an economic stimulus to the Greater Fresno region, including
5 potentially through additional job and contracting opportunities.. In
6 particular, PG&E's union collective bargaining agreements generally exceed
7 California prevailing wage requirements, and in order to obtain the
8 30 percent IRA bonus ITC rate, further discussed in Chapters 2 and 4 of this
9 Prepared Testimony, PG&E must satisfy federal government prevailing
10 wage and apprenticeship requirements for laborers and mechanics
11 employed in the construction, alternation, and repair of the Helms Pumped
12 Storage Project. These prevailing wage and apprenticeship requirements
13 are applicable to PG&E employees, contractors, and subcontractors, many
14 of whom are likely to live in the area surrounding Helms. As a result, the
15 Helms Uprate Project will provide economic opportunities in the Greater
16 Fresno region.

17 **F. Report of the Independent Evaluator**

18 PG&E engaged Wayne Oliver of Merrimack Energy as the
19 Commission-approved independent evaluator to review PG&E's evaluation of
20 the Helms Uprate opportunity and to opine on the reasonableness and fairness
21 of that evaluation against other third-party procurement opportunities.
22 Mr. Oliver's report is Attachment C to this chapter.

69 *Id.*, at p. 7.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT A

**PG&E'S 2022 INTEGRATED RESOURCE PLAN:
ADDITIONAL PROCUREMENT FOR THREE SCENARIOS**

TABLE 7*
ADDITIONAL PROCUREMENT FOR 30 MMT CONFORMING PORTFOLIO (MW)

Line No.	Tehnology	2024	2026	2030	2035
1	Solar PV				
2	Arizona	0	0	127	127
3	Kramer	0	0	444	444
4	Riverside	0	0	711	711
5	Tehachapi	0	0	594	594
6	Wind				
7	Baja California	0	0	120	120
8	Carrizo	0	0	57	57
9	Central Valley	0	0	35	35
10	Humboldt	0	0	7	7
11	Kern Greater Carrizo	0	0	12	12
12	Northern California	0	0	173	173
13	Solano	0	0	112	112
14	Southern Nevada	0	0	88	88
15	Southwest Existing	0	0	53	53
16	Tehachapi	0	0	55	55
17	New Transmission Wind				
18	Humboldt Bay Offshore	0	0	0	179
19	Morro Bay	0	0	39	620
20	New Mexico	0	0	500	500
21	Wyoming	0	0	89	466
22	Storage				
23	Battery Storage	0	0	0	1,167
24	Total Portfolio Resource Additions	0	0	3,217	5,521

*Tables are from PG&E's 2022 Integrated Resource Plan filed with CPUC on November 1, 2022; pages 34-36.

TABLE 8*
ADDITIONAL PROCUREMENT FOR 25 MMT CONFORMING PORTFOLIO (MW)

Line No.	Tehnology	2024	2026	2030	2035
1	Solar PV				
2	Arizona	0	0	166	166
3	Imperial	0	0	0	38
4	Kramer	0	0	754	754
5	Riverside	0	0	646	646
6	Tehachapi	0	0	113	543
7	Wind				
8	Baja California	0	0	109	109
9	Carrizo	0	0	52	52
10	Central Valley	0	0	31	31
11	Humboldt	0	0	6	6
12	Kern Greater Carrizo	0	0	0	11
13	Northern California	0	0	157	157
14	Solano	0	0	102	102
15	Southern Nevada	0	0	0	80
16	Southwest Existing	0	0	91	91
17	Tehachapi	0	0	50	50
18	New Transmission Wind				
19	Humboldt Bay Offshore	0	0	0	247
20	Morro Bay	0	0	0	564
21	New Mexico	0	0	455	455
22	Wyoming	0	0	423	423
23	Storage				
24	Battery Storage	0	0	0	1,102
25	Total Portfolio Resource Additions	0	0	3,156	5,627

*Tables are from PG&E's 2022 Integrated Resource Plan filed with CPUC on November 1, 2022; pages 34-36.

TABLE 9*
ADDITIONAL PROCUREMENT FOR 30 MMT ATE ALTERNATIVE PORTFOLIO (MW)

Line No.	Tehnology	2024	2026	2030	2035
1	Solar PV				
2	Arizona	0	0	29	29
3	Kramer	0	0	121	1,072
4	Riverside	0	0	611	833
5	Tehachapi	0	0	567	1,258
6	Southern Nevada	0	0	713	713
7	PG&E	0	0	69	69
8	Wind				
9	Baja California	0	0	120	120
10	Carrizo	0	0	57	57
11	Central Valley	0	0	35	35
12	Humboldt	0	0	7	7
13	Kern Greater Carrizo	0	0	12	12
14	Northern California	0	0	152	152
15	Solano	0	0	112	112
16	Southern Nevada	0	0	88	88
17	Southwest Existing	0	0	53	100
18	Tehachapi	0	0	55	55
19	New Transmission Wind				
20	Humboldt Bay Offshore	0	0	0	321
21	Morro Bay	0	0	39	620
22	New Mexico	0	0	500	500
23	Wyoming	0	0	98	466
24	Storage				
25	Battery Storage	0	0	1,127	4,809
26	Total Portfolio Resource Additions	0	0	4,565	11,429

*Tables are from PG&E's 2022 Integrated Resource Plan filed with CPUC on November 1, 2022; pages 34-36.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT B

COMPARATIVE TABLE

Comparator Group

Agreement Type	Counterparty (Project Name)	Technology	Online Date	Duration (Hours)	Term (Years)	Capacity (MW)**	Present Value (2024 dollars) \$ millions	Levelized \$ per kW-year	Status
UOG	Helms Uprate - higher capacity	Pumped Storage	1/1/2031*	>8	38	156	\$96	\$67	
UOG	Helms Uprate - lower capacity	Pumped Storage	1/1/2031*	>8	38	129	\$15	\$13	

* The expected online dates are first unit EOY 2029, second unit EOY 2030, third unit EOY 2031.

**For Helms this is the capacity increase at point of interconnection, for PPAs this is the contract MW

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
ATTACHMENT C
INDEPENDENT EVALUATOR REPORT

12/18/2023

PG&E Helms Uprate Long Duration Energy Storage Project

Final REPORT OF THE INDEPENDENT EVALUATOR

prepared by



Final Report of Merrimack Energy Group, Inc.

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1. INTRODUCTION

1.1 Overview

Pacific Gas & Electric Company ("PG&E") is submitting an Application to the California Public Utilities Commission ("CPUC") seeking approval of the Helms Uprate Project ("Uprate") to increase the nameplate generation capacity of PG&E's existing Helms Pumped Storage Plant ("Helms") by 150 MW to 180 MW.¹ The project is located in Fresno County with the point of interconnection at the Gregg substation in Fresno, CA. The opportunity to increase the nameplate generation capacity of PG&E's existing Helms Pumped Storage Plant is supplemental to the needed lifecycle maintenance work on the facility. The increased nameplate generation capacity aims to provide cost-effective long-duration energy storage as sought in the Mid-Term Reliability procurement rulings. The Uprate project plans to upgrade each of the three existing generating/pumping units targeting completion of one unit per year in each of the years 2029 through 2031. Within the next ten years, some major generation equipment needs lifecycle replacement, and the Uprate project would utilize improved design as part of the lifecycle replacement work to achieve increased nameplate capacity at an incremental cost.

In its Application, PG&E notes that the Helms Uprate includes the Lifecycle Replacement Work and the proposed investment needed to increase the nameplate capacity by 150 to 180 MW. The Lifecycle Replacement Work is needed to maintain Helm's existing generation and pumping capacity into the middle of the next century. Without the Lifecycle Replacement Work, Helm's capability will degrade. In addition to maintaining Helms as a future resource, the Lifecycle Replacement window provides an opportunity to increase the generation capacity.

PG&E estimates that the Uprate will result in capital expenditures of \$462.2 million (nominal), inclusive of an interconnection cost estimate of about \$12 million as a placeholder for non-reimbursable interconnection costs. This does not include an estimate for FERC-jurisdictional reimbursable network upgrade costs. PG&E estimates that removing from that total forecast the estimated cost that PG&E would incur to undertake the otherwise needed Lifecycle Replacement Work and further subtracting 30% federal Investment Tax Credit ("ITC"), the net cost forecast

¹ PG&E noted in its Application that the corresponding net increase at the point of interconnection is estimated to be 129 – 156 MW. The net capacity increase at the point of interconnection is less than the unit nameplate capacity increases due to transformer and transmission line losses between the unit and the point of interconnection at Gregg Substation in Fresno, CA, approximately 60 miles from Helms. The Uprate will also seek to increase pumping capacity proportional to the increase of generation capacity. The target online dates are end of the year 2029-2031 (1 unit per year) with an estimated earliest date of Resource Adequacy (RA) Full Capacity Deliverability Status (FCDS) eligibility at the end of the year 2030.

Final Report of Merrimack Energy Group, Inc.

to obtain the incremental capacity associated with the Uprate project is \$27 million.² PG&E plans to incorporate the increase in capacity with planned Lifecycle Replacement Work and expects to receive an ITC benefit due to the Uprate.

PG&E notes that there are three main drivers for proposing the Uprate now. The first driver is to support the State of California's long-duration energy storage procurement goals. Long-duration energy storage is needed to ensure grid reliability while meeting increasing electricity demand. Second, most of the major generation equipment components at Helms are due for lifecycle replacement in the next 10 years, presenting a fleeting and unique opportunity to undertake the Uprate in a cost-effective manner at the same time. Third, the Uprate is designed to take advantage of federal tax incentives under the Inflation Reduction Act ("IRA").

PG&E is seeking CPUC approval to recover the incurred costs of the Uprate in rates up to a cap based on the forecast of costs.

PG&E requested that Merrimack Energy Group, Inc. ("Merrimack Energy") serve as Independent Evaluator ("IE") for the Helms Uprate project application process. Merrimack Energy has served as the IE for all three phases of PG&E's Mid-Term Reliability ("MTR") procurement processes and was retained as IE for the Helms Uprate project by PG&E in mid-November, 2023.

1.2 Regulatory Requirements for the IE

The requirements for participation by an IE in utility solicitations are outlined in Decisions ("D").04-12-048 (Findings of Fact 94-95, Ordering Paragraph 28), D.06-05-039 (Finding of Fact 20, Conclusion of Law 3, Ordering Paragraph 8) of the CPUC, D.09-06-050 and D.10-07-042.

In D.04-12-048 (December 16, 2004), the CPUC required the use of an IE by investor-owned utilities (IOUs) in resource solicitations where there is an affiliated bidder or bidders, or where the utility proposed to build a project or where a bidder proposed to sell a project or build a project under a turnkey contract that would ultimately be owned by a utility. The CPUC generally endorsed the guidelines issued by the Federal Energy Regulatory Commission ("FERC") for independent evaluation where an affiliate of the purchaser is a bidder in a

² In its Application, as well as in response to a question from Merrimack Energy, PG&E estimates that the entire project cost is \$462 million, including 50% contingency on all project components. The cost includes an estimated \$300 million in nominal dollars for lifecycle capital replacement work and an incremental cost of \$162 million for the Uprate. The ITC is applied to \$450 million in total cost which excludes an estimated \$12 million for the estimated interconnection cost from the total cost. The estimated 30% ITC benefit is calculated to be \$135 million, which results in a total cost for the Uprate of \$27 million.

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competitive solicitation, but stated that the role of the IE would not be to make binding decisions on behalf of the utilities or administer the entire process.³ Instead, the IE would be consulted by the IOU, along with the Procurement Review Group ("PRG") on the design, administration, and evaluation aspects of the Request for Proposals ("RFP"). The Decision identifies the technical expertise and experience of the IE with regard to industry contracts, quantitative evaluation methodologies, power market derivatives, and other aspects of power project development. From a process standpoint, the IOU could contract directly with the IE, in consultation with its PRG, but the IE would coordinate with the Energy Division.

In D.06-05-039 (May 25, 2006), the CPUC required each IOU to employ an IE regarding all RFPs issued pursuant to the RPS, regardless of whether there are any utility-owned or affiliate-owned projects under consideration. In addition, the CPUC directed the IE for each RFP to provide separate reports (a preliminary report with the shortlist and final reports with IOU advice letters to approve contracts) on the entire bid, solicitation, evaluation and selection process, with the reports submitted to the utility, PRG, and CPUC and made available to the public (subject to confidential treatment of protected information). The IE would also make periodic presentations regarding its findings to the utility and the utility's PRG consistent with preserving the independence of the IE by ensuring free and unfettered communication between the IE and the CPUC's Energy Division, and an open, fair, and transparent process that the PRG could confirm.

In D.09-06-050 issued on June 18, 2009 in Rulemaking 08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California Renewable Portfolio Standard Program, the CPUC required that bilateral contracts should be reviewed according to the same processes and standards as contracts that come through a solicitation. This includes review by the utility's PRG and its IE, including a report filed by the IE.

In D.10-07-042 issued on July 29, 2010, the Commission reaffirmed the role of the IE and required the Energy Division to revise the IE Template to ensure that the IEs focus on their core responsibility of evaluating whether an IOU conducted a well-designed, fair, and transparent RFO for the purpose of obtaining the lowest market prices for ratepayers, taking into account many factors (e.g. project viability, transmission access, etc.).

This IE report is submitted in conformance with the above requirements and is generally consistent with the requirements outlined in the CPUC's Short Form IE Report Template.

³ Decision 04-12-048 at 129-37. The FERC guidelines are set forth in *Ameren Energy Generating Company*, 108 FERC ¶ 61,081 (June 29, 2004).

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1.3 Issues Addressed in this Report

This report addresses Merrimack Energy's assessment regarding the following issues associated with the evaluation of the Helms Uprate project.

1. Review the background information associated with the Helms Uprate project;
2. Review and assess the basis for PG&E pursuing the Helms Uprate project;
3. Review the cost assessment and evaluation results associated with the evaluation of the Helms Uprate project in comparison to the shortlisted projects selected by PG&E for contract execution via the current Mid-Term Reliability procurement Phase 3 process;
4. Provide recommendations regarding the Helms Uprate project.

1.4 Description of the Role of IE Throughout the Process

Merrimack Energy's role during the development of the Application process included the following:

- Merrimack Energy reviewed the various chapters of PG&E's Application and held discussions with members of the PG&E MTR procurement team to discuss the project;
- Based on review of documents and comparative evaluation results, Merrimack Energy prepared a number of questions associated with the project and its evaluation to ensure we had full transparency regarding project information;
- Reviewed the input assumptions and evaluation results for the Mid-Term Reliability Phase 3 shortlisted proposals along with the evaluation results for the Helms Uprate project to ensure that the evaluations were consistent with the MTR3 methodology, inputs and results;
- Prepared the final IE Report for filing with Application.

2. REGULATORY BACKGROUND TO RESOURCE DECISION

The CPUC's Final Decision Requiring Procurement to Address Mid-Term Reliability (2023 – 2026) in Rulemaking 20-05-003 addresses the mid-term reliability needs of the electricity system within the California Independent System Operator's (CAISO's) operating system by requiring at least 11,500 MW of additional net qualifying capacity (NQC) to be procured by all of the load serving entities ("LSEs") subject to the Commission's integrated resource planning (IRP) authority.⁴ The overall capacity requirements are adopted annually beginning with 2,000 MW by 2023, an additional 6,000 MW by 2024, an additional 1,500 MW by 2025, and an additional 2,000 MW by 2026.

The Final Decision also stated that the CPUC expects that all of the resources procured pursuant to this order will be zero-emitting, unless they otherwise qualify under the renewable portfolio standard eligibility requirements. The 2026 resources are required to be long-lead time resources,⁵ with half coming from long-duration storage and the other half from firm zero-emitting resources or those that otherwise qualify as eligible under the renewable portfolio standard program and have at least an 80 percent capacity factor. Incremental capacity from fossil-fueled resources will not be eligible to qualify under this order.

LSE's will be required to submit procurement information twice yearly, consistent with Decision D.20-12-044 requirements, to show progress toward the capacity procurement requirements in this decision. Backstop procurement to be conducted by the IOUs may be ordered by the Commission once yearly, with the costs allocated to the deficient LSEs and/or their customers. In addition, deficient LSEs will be subject to penalties for failing to deliver the capacity required in 2023 – 2025 at the level of the net cost of new entry (CONE). The Final Decision also identified the estimated annual procurement amounts that would be required from all LSE. Cumulative capacity requirements totaled 11,500 MW from 2023 to 2026, including 2000 MW in 2023, 6,000 MW additional in 2024, 1,500 MW additional in 2025 and 2,000 additional MW in 2026.

In terms of eligible resources, the Final Decision proposed that at least 1,000 MW of geothermal resources and 1,000 MW of long-duration storage (defined as

⁴ In Decision 23-02-040 (February 23, 2023), the CPUC required supplemental mid-term reliability procurement of a total of 4,000 MW of NQC in addition to the 11,500 MW ordered in D. 21-06-035, with the additional procurement for 2026 and 2027.

⁵ Long lead-time resources required by this order by June 1, 2026 shall be defined as: (a) at least 1,000 MW of long-duration storage (able to deliver at maximum capacity for at least eight hours from a single resource); and (b) at least 1,000 MW of generation capacity that has no on-site emissions or is eligible under the requirements of the renewable portfolio standard program, and has at least 80 percent capacity factor. The resource must not be use limited or weather dependent. No storage projects shall qualify under this provision.

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providing 8 hours of storage or more) should be required as part of the overall procurement requirement by no later than 2026. The Final Decision also identified obligations for each LSE. PG&E's bundled obligations included 400 MW in 2023, 1,201 MW in 2024, 300 MW in 2025, and 400 MW in 2026. Of this total, the minimum capacity for zero-emitting resources⁶ by 2025 was set at 500 MW. The IOU's may propose to meet a portion of their capacity required by this order with utility-owned resources under the terms set in Decision 19-11-016, and must file a full application with any such proposal, for the Commission's consideration.

Decision D.23-02-040 issued on February 23, 2023 addressed two primary topics: (1) the Decision requires supplemental mid-term reliability procurement of a total of 4,000 MW of NQC in addition to the 11,500 MW ordered previously in Decision (D.) 21-06-035. This additional procurement is for 2026 and 2027. Also, the requirements for procurement of long-lead time ("LLT") resources from D. 21-06-035 are automatically postponed to 2028; (2) This decision recommends electricity resource portfolios to the California Independent System Operator to study in its 2023-2024 Transmission Planning Process.

In the LLT category, PG&E has procurement requirements of 200 MW of Long Duration Energy Storage and 200 MW of Firm Zero-Emitting. To date, PG&E has not successfully procured any resources qualifying for the LDES procurement.

In Chapter 3 of its Application, PG&E illustrates examples of state policy supporting long-duration storage, such as pumped storage. Merrimack Energy's own experience as Independent Evaluator in many areas of the country illustrates a real interest on the part of utilities and policy makers for pumped storage options as a long-duration storage resource. While we have seen such projects proposed in other solicitations, two primary issues are affecting the procurement of these resources: (1) the in-service date of these projects is generally beyond the utility planning and procurement horizon for meeting capacity and energy requirements; and (2) the capital and operating costs of new greenfield pumped storage projects is high and the development timeframes are lengthy which results in these projects generally being uncompetitive with other storage options. Merrimack Energy has not observed a proposal for an expansion of an existing pumped storage project bid into a utility solicitation process.

Given that the expected In-Service date of the final phase of the Uprate project is in 2031, at this time, PG&E does not expect that the Helms Uprate project would qualify for the current online requirement of 2028 for Mid-Term Reliability. Despite

⁶ Zero-emitting capacity shall have the following characteristics: (a) be from a generation resource, a generation resource paired with storage (physically or contractually), or a demand response resource; (b) be available every day from 5 p.m. to 10 p.m. (the beginning of hour ending 1800 through the end of hour ending 2200), Pacific time, at a minimum; and (c) be able to deliver at least 5 MWh of energy during each of these daily periods for every MW of incremental capacity claimed.

this, the Helms Uprate project aligns with a large number of state objectives aimed at improving system reliability.

3. ECONOMIC ANALYSIS

As described earlier, the Helms Power Plant generation capacity would be increased from 1,212 MW to 1,392 MW, an increase of 150 MW up to 180 MW of nameplate capacity, with a net capacity increase at the point of interconnection of 129 to 156 MW.

The Helms Uprate is proposed as incremental long-duration storage that would help further the integration of California's growing intermittent renewable resource and promote grid stability and resiliency through the operational flexibility of the resource. At a time when a majority of the storage resources being procured are four-hour lithium-ion battery projects, the Uprate project also promotes technological diversity. The Uprate project would achieve an increase in resource capacity through the already planned Lifecycle Replacement Work. In addition, PG&E expects to receive investment tax credits through the IRA.

While Merrimack Energy reviewed the cost estimate work paper, Merrimack did not undertake an independent cost estimate assessment to determine the accuracy of estimates for the various equipment upgrades.

4.1 Input Assumptions

PG&E utilized its evaluation protocol and input assumptions to determine the Net Market Value ("NMV") of the Uprate project, which is the same methodology and input assumptions used in PG&E's Mid-Term Reliability Phase 3 RFO.⁷ The Net Market Value ("NMV") is calculated based on the summation of several components as follows:

Net Market Value: $NMV = E + A + C + R - (V + F + MC + T - BC)$ ⁸ where

C = Capacity Value

E = Energy Value

⁷ In the internal evaluation protocols for the Mid-Term Reliability RFO Phase 3, PG&E provided a description of the evaluation methodology for comparing the valuation of proposals submitted. PG&E noted that a net market value assessment will be performed on all Offers by comparing an Offer's costs to its benefits. Next, PG&E will include a Portfolio Fit Adjustment to create an Adjusted Net Market Value. An Adjusted Net Market Value for each project will be measured in present value \$/kW and then projects will be ranked from highest to lowest within each procurement category.

⁸ The components of the NMV calculation provided above may vary depending on the product being evaluated. For NMV calculations of the Helms Uprate project, the fixed cost portion of the equation is replaced by the revenue requirements for the project.

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A = Ancillary Service (A/S) Value
R = REC Value
V = Variable Cost
F = Fixed Cost
MC = Metered Contract Cost
T = Transmission Network Upgrade Cost
BC = Bridging Costs

For the Uprate project, the NMV is calculated based on the forecasted revenues from the Uprate project minus the forecasted costs, or the revenue requirements, over the expected useful life of the project.⁹ On the revenues side, PG&E utilizes their Storage Valuation Model, which is also used in the Mid-Term Reliability Phase 3 evaluation. There are three main components included on the revenue side of the equation: energy value, capacity value, and ancillary service value.

Energy Value

For the Mid-Term Reliability RFO – Phase 3 process, the Energy Value component applies to several Agreement options including RPS Contract Type, RA Agreement with Energy Settlement, and Utility-owned Build Own Transfer Agreement.

For RPS contracts, the energy value for each hour of delivery is estimated by multiplying the quantity of energy delivery for an hour multiplied by the forward energy price for that hour at the LMP. The LMP price is determined from the corresponding Trading Hub (i.e., NP15, SP15, or ZP26) adjusted for congestion and losses for that hour. The quantity of energy delivery for each hour is determined by the hourly generation profile of the offer.

For Long-Term RA Agreements with Energy Settlement, the energy value is the Energy Settlement value. This is a financial payment from the counterparty to PG&E. The energy value is calculated by following the payment formula in the contract and the hourly forward curves at the LMP location. The energy settlement value is driven by the Day-Ahead Price, round trip efficiency of the project, and the Offer's Variable O&M costs.

For utility-owned projects such as the Uprate option, PG&E dispatches the energy storage facility. The Energy Gross Margin is the projected energy net revenue subtracting variable cost associated with the dispatch schedule obtained by running PG&E's Storage Valuation Model, which dispatches Energy storage for each price scenario using deterministic optimization. The objective of this

⁹ Fixed cost is calculated as the present value of annual revenue requirements (PVRR) calculated by PG&E's Revenue Requirements Model using the Helms project costs.

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deterministic optimization is to maximize the Energy Gross Margin, while meeting operating constraints based on forecast of energy price in a given price scenario. For each price scenario, Energy Value is the net present value of hourly energy values across all hours during the delivery period. Energy Value is then divided by the net present value of kW-year of Dmax (Maximum Discharge Power) to be expressed in terms of levelized dollars per kW-year.

Similarly, Variable Cost is the net present value of hourly variable costs, including VOM and start-up costs for the hour across all hours during the delivery period.

The quantity of energy delivery for each hour is determined by PG&E's energy-only optimization algorithm with forecasted hourly energy prices at the project LMP. The forecasted hourly energy prices are set as the same as energy prices for the previous day of the same day type (weekdays vs weekends). The energy-only optimization algorithm solves for the energy delivery (both charging and discharging) schedules that maximize the sum of net energy revenue minus variable cost under the operating constraints of the Offer. The optimization algorithm considers the variable costs such as Variable O&M and start-up costs in its objective function. The optimization algorithm considers the operating parameters and constraints such as minimum run time, minimum down time, minimum and maximum operating MW when charging and discharging (Dmax, Dmin, Cmax and Cmin), storage energy size constraints and energy balance constraints considering efficiency loss. The calculation will be performed using PG&E's Storage Valuation Model.

Capacity Value

Capacity value is the net present value of monthly capacity values across all months during the delivery period.

The monthly Capacity Value C is computed as the sum of two components: (1) the monthly Net Qualifying Capacity ("NQC") multiplied by the Local or System capacity price, and (2) the monthly Effective Flexible Capacity (EFC in MWs) provided by the project multiplied by the flexible RA price. These values are then discounted back by the discount factor for the month.

The amount of NQC and EFC are calculated based on the operational characteristics specified in the offer form and assume current counting rules. Given ongoing Commission activity on RA reform and Energy Division work on ELCC values, these values are likely to change as more information becomes available.

Ancillary Service (A/S) Value

To the extent that the resource is certified by CAISO to provide Regulation and/or Spin, A/S Value is calculated based on the incremental value that A/S capability provides in addition to Energy Gross Margin. This is calculated as the difference between (a) Spot Gross Margin and (b) Energy Gross Margin. The Spot Gross Margin is the net revenue minus variable costs when providing both A/S and energy, while Energy Gross Margin is net revenue minus variable costs when providing energy only. The Spot Gross Margin is calculated from the optimal energy and A/S (RegUp, RegDn and Spin) schedules obtained by solving the co-optimization model that maximizes the Spot Gross Margin under the operating parameters and constraints of the Offer.

The amount of energy and A/S delivery for each hour is determined by the co-optimization algorithm in PG&E's Storage Valuation Model.

Merrimack was provided with the energy, ancillary service, and resource adequacy cost curves. The energy and resource adequacy cost curves were the same values used in the Mid-Term Reliability Phase 3 evaluation. The RA cost curve has a vintage of June 7, 2023 and the energy cost curve has a vintage of July 26, 2023. In addition, PG&E utilized the same ELCC values in the Helms Uprate analysis as is used in the Mid-Term Reliability Phase 3 evaluation.

4.2 Quantitative Evaluation Results

On the cost side, PG&E calculates the Helms Uprate project cost to be \$162.3M, which is the difference between the total capital expenditures of \$462.2M (this includes \$12.2M¹⁰ in Customer Interconnection Facilities Costs) and the life cycle replacement costs alone of \$299.9M. PG&E has determined that all project costs will qualify for the 30% federal investment tax credit ("ITC"), which would total \$135.5M. When accounting for the life cycle replacement costs and the investment tax credit benefits, PG&E assumes an incremental cost of approximately \$27M for the additional capacity achieved via the Uprate project.

¹⁰ Interconnection costs are only an unsubstantiated estimate at this time. PG&E noted that it is anticipated that interconnection for the greater nameplate capacity created by the Uprate will require replacement or installation of substation and/or transmission related components. The existing interconnection facilities for Helms include two 230 kV generation tie transmission lines that connect the Helms Switchyard to the Gregg Substation. PG&E also notes that an interconnection study request was submitted to the CAISO in March 2023. The request was included by CAISO in Cluster 15 of its study process. The study is slated to begin in April 2024 and is expected to take 2-3 years to complete. PG&E used the CAISO Reliability Network Upgrade Reimbursement Maximum values as the basis for calculating an interconnection cost estimate of at this time since no interconnection studies have been completed.

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Table 1: Uprate Project Cost Assumptions

Project Component	Cost (\$M)
Total Project Cost (A)	\$462.2
Interconnection Upgrade Costs (B)	\$12.2
ITC-Eligible Project Costs (C=A-B)	\$450
Investment Tax Credit (D=0.30*C)	\$135.5
Lifecycle Replacement Costs (E)	\$299.9
Uprate Incremental Project Cost (F=A-E)	\$162.3
Uprate Cost after ITC Benefits (G=F-D)	\$26.8

Merrimack Energy submitted questions to PG&E regarding the cost assumptions, including the level of the ITC benefits associated with the full cost of the project minus interconnection costs and also had a discussion with PG&E about the basis for their conclusion regarding qualification for ITC benefits. PG&E informed the IE that they had been working with outside counsel who had significant experience with regard to the treatment of ITC benefits included in the IRA. Merrimack Energy is not an expert with regard to the implications of tax credits resulting from the IRA. As a result, the IE's review and assessment is based on the proposal submitted by PG&E with regard to the expected ITC benefits.

PG&E intends to reduce the revenue requirements impact with eligible tax credits from the IRA. PG&E assumes that entire project cost of \$462.2M, less the interconnection upgrade costs of \$12.2M, would be eligible for the 30% ITC. The total amount of tax credits available depends on numerous requirements. For example, if prevailing wage and apprenticeship requirements are not met, the ITC can be reduced from 30% to 6%. The prevailing wage and apprenticeship requirements also apply to any alteration or repair of the facility during the first ten years of operation.

The total investment amount also includes the Allowance for Funds Used During Construction ("AFUDC"), which is the product of the Construction Work-in-Progress ("CWIP") amount and PG&E's before tax weighted cost of capital ("WACC") of 7.28%.

In the revenue requirements model, PG&E also includes the recovery of costs for federal income taxes, California state income tax, and property taxes. In addition, PG&E includes the depreciation of the investment over the expected useful life of 38 years with no salvage value.

PG&E analyzed two scenarios. For scenario 1, the incremental generating capacity of the Uprate project is 156 MW with 78 MW of increased capacity for generation and pumping at the interconnection point, whereas Scenario 2 has an incremental capacity of 129 MW and 0 MW of increased capacity for generation and pumping. Table 2 below provides the components of cost and

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revenues under each scenario. PG&E calculated the net present value in millions of dollars as well as levelized dollars per kW-year. Since the Mid-Term Reliability selections rank and select based on the levelized NMV results, Table 3 provides the NMV components and results in levelized dollars per kW-year.

Table 2: Helms Uprate Net Market Value Results – Levelized \$/kW-year

Scenario	Revenue Requirement	Energy Revenue	Ancillary Service Revenue	Resource Adequacy Value	Network Upgrade Cost	Net Market Value	Portfolio Adjustment	NMV with Port Adj
Scenario 1 – 156 MW Incremental Capacity	\$(64.50)	\$57.50	\$5.30	\$72.10	\$(6.70)	\$63.70	\$3.50	\$67.2
Scenario 2 – 129 MW incremental capacity	\$(78.00)	\$17.30	\$4.50	\$72.10	\$(6.70)	\$9.30	\$3.50	\$12.7

For both scenarios the same scope of work is required. PG&E is pursuing the higher capacity scenario; however, the total MW capacity increase cannot be verified until the turbine model testing is completed in 2024 or 2025. The lower capacity scenario 2 represents a more conservative estimate of the capacity addition from the Helms Uprate project pending the turbine testing results.

Merrimack reviewed the revenue requirements and NMV calculations for both scenarios. A list of questions was sent to PG&E to provide the basis for the calculations. PG&E provided detailed, sufficient responses to all of Merrimack's questions. Merrimack also notes that the ITC is calculated based on the entire project cost estimate inclusive of the lifecycle replacement costs; however, the entire amount of ITC benefits is applied to the Uprate's incremental costs, which results in an Uprate cost of \$26.8 million utilized for the economic comparison of the Uprate relative to shortlisted battery energy storage projects selected via the Mid-Term Reliability Phase 3 RFO.

In order to determine the cost effectiveness of the Helms Uprate scenarios, PG&E has compared the levelized NMV results to the recently shortlisted proposals from the Mid-Term Reliability Phase 3 solicitation. All shortlisted projects are Battery Energy Storage options. While there are no utility-ownership options included in the shortlist, Merrimack agrees that this comparison is the most appropriate method to evaluate the Helms Uprate project's cost effectiveness since the shortlist represents the best projects selected as a result of the ongoing Mid-Term Reliability Phase 3 RFO as the most current solicitation process with the most current data.

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Table 3: Comparison of Helms Uprate to MTR Phase 3 Resources

Project	Technology	Agreement Type	Online Date	Term	Capacity (MW)	Storage Duration (hrs)	Levelized NMV (\$/kW-year) ¹¹
Helms Uprate Scenario 1	Pumped Storage	UOG	1/1/2031 ¹²	38	156	>8	\$67
Helms Uprate Scenario 2	Pumped Storage	UOG	1/1/2031 ¹²	38	129	>8	\$13

The results of the analysis clearly demonstrates that the Helms Uprate compares very favorably to the shortlisted proposals under negotiations at this time, offering long-duration storage with a Levelized Net Market Value that [REDACTED] offers for 4-hour duration batteries.

4.3 Benchmark Cost Assessment for Pumped Storage Hydro Projects

As noted previously, there is considerable market interest from power buyers for pumped storage projects given the long-duration nature of the storage and the operational flexibility of these projects. Merrimack Energy has served as Independent Evaluator for All Source solicitations where pumped storage projects have been submitted as proposals for long lead-time resources. These projects have been inhibited by the long-lead times for project development that are generally outside the utility's planning and procurement horizon and high capital and operating costs. Table 4 below presents benchmark cost examples for pumped storage hydro projects from several public sources.

¹¹ A Portfolio Adjustment was applied to the proposal submitted into the Mid-Term Reliability Phase 3 solicitation process as well. The Levelized NMV values in this column reflect the Portfolio Adjustment values applied to each proposal.

¹² The expected online dates for the Helms Uprate are for the first unit at end of the year 2029, second unit end of the year 2030, and the third unit end of the year 2031.

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Table 4: Benchmark Costs for Pumped Storage Hydro Projects from Public Sources

Information Source	Capital Cost (\$/kW)	Fixed O&M (\$/kW-year)	Variable O&M (\$/MWh)
National Renewable Energy Laboratory Annual Technology Baseline (ATB) – 2022	\$1,999 - \$5,505	\$18.00	\$0.51
National Renewable Energy Laboratory Annual Technology Baseline (ATB) – July 2023	\$2,250-\$4,434	\$18.70	\$0.54
PacifiCorp 2023 Integrated Resource Plan	\$4,303 for a 400 MW project	\$18.00	\$.51
Puget Sound Energy 2023 Electric Progress Report	\$3,602 - \$3,910	\$18.00	\$.26
US Department of Energy (DOE) – Technology Strategy Assessment Pumped Storage Hydro, July 2023	\$2,207 – 1,000 MW for 10-hour storage		
US Department of Energy (DOE) – Technology Strategy Assessment Pumped Storage Hydro, July 2023	\$2,625 – 100 MW for 10-hour storage		

Merrimack Energy has also reviewed a few proposals for pumped storage hydro projects bid into request for proposal processes. We have generally seen capital costs in the range from [REDACTED].

The interconnected generating capacity of the Helms Uprate project has an estimated interconnected generation capacity of 129 MW to 156 MW. The estimated capital cost of Helms Uprate is estimated to be \$162 million. At the low end of the capacity range at 129 MW, the capital cost for the Uprate could range from \$1,256/kW, without factoring in any ITC benefit. At the higher capacity levels of 156 MW, the capital cost of Uprate would be \$1,038/kW, both lower than the benchmark options identified above.

4.4 Project Viability Assessment

The Helms Uprate project offers several project viability benefits that are certainly not available with development of a new greenfield pumped storage project. The project has site control with minimal impact on land use, since all work on the project will take place within the existing footprint. The project will provide additional resource diversity through the capacity expansion of the project. The

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Helms capacity is located in the Greater Fresno Local Capacity Area that is expected to experience load growth of about 700 MW by 2028.

The main unknown viability issue is related to any network upgrade costs. PG&E has submitted an Interconnection Study request with CAISO to be included in the Cluster 15 interconnection study process. Therefore, the network upgrade costs won't be known until the Cluster 15 study process is completed, which could take a couple years. The revenue requirements analysis does not include these costs because they will be recovered from customers through FERC-approved transmission rates, however, the impact of these costs are accounted for in the evaluation results. Based on the CAISO's Reliability Network Upgrade Reimbursement Maximum methodology and inflation factor, PG&E estimated network upgrade costs to be \$15.8M for Scenario 1 and \$13.1M for Scenario 2, which amounts to \$101,549/MW. PG&E determined this amount by increasing the maximum Reliability Network Upgrade reimbursement amount as published by the CAISO of \$85,430/MW¹³ by 2.5% per year until the online date of January 1, 2031.

5. SAFEGUARDS TO COMPARE UTILITY-OWNED GENERATION OPTIONS

For the Mid-Term Reliability RFO – Phase 3, PG&E used its existing Internal Confidentiality Protocol that was implemented in the previous Mid-Term Reliability RFO Phase 2. The Mid-Term Reliability RFO – Phase 3 seeks offers from third parties for both third party-owned and utility-owned projects via a Build Own Transfer ("BOT") arrangement that will provide system-level net qualifying capacity ("NQC"). Prior CPUC decisions require PG&E to ensure the unbiased evaluation of all offers and to avoid providing an unfair advantage to Utility-owned offers when such offers compete for selection and execution in an RFO with third-party offers. PG&E is not submitting or reserving the right to submit its own bid into this RFO. Therefore, there are no PG&E employees involved in preparing bids for projects that would be owned by the utility. Instead, PG&E is seeking offers for BOT options for projects that would be constructed by a third-party on their own site. The utility-ownership team is responsible for developing the project specifications and evaluating, selecting, and negotiating third-party off-take offers.

The Internal Confidentiality Protocol is designed to ensure that an appropriate internal level of confidentiality of confidential RFO information is maintained. With this Confidentiality Protocol, PG&E is focusing on the type of information that

¹³ <https://www.caiso.com/Documents/CurrentReliabilityNetworkUpgradeReimbursementMaximum.pdf>

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PG&E employees must keep confidential in order to avoid external perceptions of any unfair advantages afforded to Utility-Owned Offers.¹⁴.

In its Application PG&E addressed the confidentiality issue. PG&E stated: "Because the Helms Uprate was under development in parallel with PG&E's Mid-Term Reliability RFOs, PG&E put in place an internal Code of Conduct prohibiting PG&E's Helms Uprate project development team, within PG&E's Power Generation organization, from receiving market-sensitive information regarding bids in the Mid-Term Reliability RFO. The Code of Conduct identifies the team within PG&E's Energy Procurement and Policy organization that has access to and evaluates the Mid-Term Reliability RFO bids, prohibits the bid evaluation team from providing bid information to the Helms Uprate project development team, and also prohibits certain management and advisory personnel who interact with both teams from acting as a conduit to provide the Mid-Term Reliability RFO bid information to the Helms Uprate project development team. In furtherance of this Code of Conduct, all development of revenue requirements and the NMV calculations for both the Helms Uprate project and third-party-owned energy storage proposals, and the comparison between those revenue requirements and values, was undertaken by PG&E staff outside of the Helms Uprate project development team. The development team only had access to the output of these calculations for the Helms Uprate project."

6. RECOMMENDATION FOR PROJECT APPROVAL

Merrimack Energy is of the opinion that the Helms Uprate project is a unique opportunity to add long-duration Pumped Storage Hydro capacity to the grid at a potentially reasonable cost especially when compared to recent shortlist battery energy storage projects selected via the Mid-Term Reliability Phase 3 solicitation based on the estimated significant Investment Tax Credit Benefits that PG&E anticipates securing for the project. While Merrimack Energy is not an expert in determining the availability and magnitude of tax credit benefits available via the IRA, it is Merrimack Energy's understanding that PG&E has been advised that favorable ITC benefits, estimated to be \$135 million, are likely available to the project.

¹⁴ Examples of the type of information considered confidential RFO information includes: (1) Participant's confidential information as described in the RFO Protocol; (2) Internal Evaluation Protocols including quantitative models, scoring and selection criteria, and actual input assumptions such as price curves; (3) Offer data including evaluation results and selection of Offers for the shortlist and execution, including deliberations and reasons for selections. This would include information on how many offers were received, how many MWs were offered and which Participants made offers; and (4) Status of PG&E's negotiations and execution of agreements with shortlisted Participants.

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There are benefits and risks associated with the Helms Uprate project that should be considered in review and assessment of the project.

The benefits of the Uprate include the following:

- For PG&E's Scenario 1 and 2, there are obvious quantitative benefits relative to other resource options being considered via recent solicitations with the Net Market Value being higher than other shortlisted projects on the shortlist in the most recent Mid-Term Reliability Phase 3 solicitation;
- In multiple regulatory proceedings, Long-Duration Energy Storage has been identified as a resource class that provides enormous benefits to the grid. The Helms Uprate project will help PG&E meet its bundled portfolio needs in the future and provide operational flexibility benefit through its quick ramping ability in response to fluctuations in demand;
- This resource offers technological diversity from the 4-hour lithium battery storage projects most often procured in recent years in California;
- The Helms Uprate provides local capacity benefits in the Fresno Local area, where the project is located;
- Through its operational characteristics, the resource provides grid resiliency during periods of peak demand for a 1-in-10 load event;
- The estimated capital cost of the Uprate compares favorably to the cost of new greenfield pumped storage hydro resources based on a comparison of the capital cost of the Uprate project (on a \$/kW installed basis) relative to benchmark costs for new greenfield pumped storage hydro projects submitted in publicly available documents. Based on that review, the capital cost of the Helms Uprate appears to be competitive and at a lower capital cost than the benchmarks.

Risks associated with Uprate project include the following:

- Since the additional capacity of the Helms Uprate project has recently been submitted for a Phase 2 study in the CAISO Interconnection Study process, the Network Upgrade costs are currently unknown. While PG&E has made a fairly conservative assumption in the economic evaluation on the potential costs that could be applied, there is a chance that the network upgrade costs are actually higher than estimated;
- If the 30% Investment Tax Credit is not achieved and applied to the entire project cost, the overall revenue requirements could increase;
- Given that this is a long lead-time resource, the cost estimates including engineering and equipment costs are preliminary estimates. PG&E has attempted to mitigate this risk by proposing a cap on cost recovery at \$462 million and applying a 50% contingency for the cost projections.

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Based on review and assessment of the proposed project benefits and costs, Merrimack feels that PG&E's Application for the Helms Uprate project should be approved.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

RATEMAKING PROPOSAL AND REVENUE REQUIREMENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
RATEMAKING PROPOSAL AND REVENUE REQUIREMENTS

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **CHAPTER 4**
3 **RATEMAKING PROPOSAL AND REVENUE REQUIREMENTS**

4 The purpose of this chapter is to present the forecasted Revenue Requirement
5 for the Helms Uprate and to describe Pacific Gas and Electric Company's (PG&E)
6 proposed methodologies for recovering the actual, incurred costs of the Helms
7 Uprate in rates, including the allocation of those costs.

8 **A. Revenue Requirement [William Ou]**

9 **1. Summary of Request**

10 The purpose of this Section A is to present the revenue requirement
11 forecast associated with the forecasted Helms Upgrade capital costs from
12 2023 through 2032 presented in Chapter 2.

13 PG&E calculates the revenue requirement forecast using the Results of
14 Operations (RO) model. The RO model compiles all capital costs as
15 presented in Chapter 2 to forecast the capital-related revenue requirement
16 that PG&E needs to recover for work presented in this application, the
17 elements of which are further described in Subsection A.2. of this chapter.
18 There is no operations and maintenance (O&M) expense forecast
19 associated with the Helms Upgrade Project in this proceeding.

20 The forecast total revenue requirement for the Helms Upgrade Projects
21 in the period 2029-2034 is \$182 million (nominal), including Revenue Fees &
22 Uncollectable (RF&U). It is calculated based on the total \$462 million in
23 forecasted capital expenditures in PG&E's Uprate Cost forecast presented
24 in Chapter 2, less an anticipated 30 percent federal Investment Tax Credit
25 (ITC) of \$135 million at that Uprate Cost forecast, for a net capital
26 expenditure forecast of \$327 million (nominal). The target planned operative
27 dates are of the respective end of calendar years 2029 through 2031, with
28 one uprated unit coming online for each of those years.

29 As further described in Chapter 2, none of the Uprate scope of work was
30 included in the list of forecasted capital expenditures in PG&E's 2023
31 General Rate Case (GRC). PG&E expects to include the cost of Lifecycle

Replacement Work¹ that is part of the Helms Uprate in its 2027 GRC Application if this Application is not resolved or is denied prior to preparation of PG&E's 2027 GRC Application. PG&E further proposes to include the ongoing revenue requirement for the Helms Uprate in PG&E's 2035 GRC, assuming the three uprated units are in service by that time as expected. In this proceeding, PG&E seeks to recover the capital revenue requirement forecast from 2029 through 2034.

After the Helms Uprate is operative, PG&E proposes to record the revenue requirement associated with actual costs and recover the costs through two separate Portfolio Allocation Balancing Account (PABA) subaccounts up to the Uprate Cost forecast of \$462 million (the "Cost Recovery Cap").² This proposed regulatory accounting treatment is discussed in Sections B-D of this Chapter.

Table 4-1 presents the forecasted revenue requirements for 2029-2034 associated with the Helms Uprate using the methodology and assumptions described in this section.

TABLE 4-1
2029-2034 REVENUE REQUIREMENT FORECAST SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	2029	2030	2031	2032	2033	2034
1	\$462	\$15,778	\$28,945	\$45,165	\$45,817	\$45,501

PG&E's capital-related revenue requirement forecast includes depreciation expense, a return on rate base, related federal and state income taxes, and property taxes. The various capital-related components of the RO calculation are discussed below.

2. Elements of the RO Calculation

a. Depreciation

Depreciation is included in the revenue requirement calculation as both depreciation expense and accumulated depreciation. Depreciation

¹ Please see Chapter 2 for a discussion and definition of this term.

² Please see Chapter 2 for more detail concerning the Uprate Cost forecast.

1 expense forecast is calculated on a straight-line, remaining-life method
2 (in accordance with the California Public Utilities Commission's
3 (Commission) Standard Practice U-4, Determination of Straight-Line
4 Remaining Life Depreciation Accruals) using Commission-approved
5 rates from depreciation accrual rate schedules effective during the
6 period for which the revenue requirement calculations are made.
7 Depreciation expense forecast is calculated by multiplying the
8 forecasted end of month plant in service balance by the corresponding
9 book depreciation rates.

10 In this application, PG&E has used the 2023 GRC adopted
11 depreciation rates for Electric Production-Hydroelectric Functional Plant.
12 PG&E will update depreciation rates if the Commission authorizes new
13 adopted depreciation rates in the next 2027 GRC, and any subsequent
14 GRCs as the first unit of Helms Upgrade project is forecasted to be
15 operative at the end of calendar year 2029.

16 **b. Rate of Return on Rate Base**

17 The forecasted rate base is calculated using utility plant less
18 adjustments for deferred taxes, depreciation reserve, and other rate
19 base offsets. Utility plant consists of the forecast cost of investment in
20 plant and equipment that is used and useful in rendering utility services.
21 In developing the forecasted rate base associated with that plant for
22 purposes of this filing, certain deductions are made. A reduction is
23 made for the accumulated deferred income taxes associated with these
24 assets. These deferred income taxes primarily result from the Modified
25 Accelerated Cost Recovery System (MACRS) tax depreciation method.
26 Rate base is also reduced by the amount of depreciation reserve
27 (i.e., the accumulated depreciation already taken in prior years) and the
28 deferred ITC tax credit).

29 PG&E multiplies the currently adopted composite Rate of Return
30 (ROR) of 7.28 percent by the weighted average rate base forecast for
31 each year to calculate the Net for Return. This calculation uses the
32 ROR and capital structure adopted in PG&E's 2023 authorized Cost of

Capital (COC) decision for years (2023-2025).³ PG&E will update the return on rate base if the Commission authorizes a new COC in a future COC proceeding.

c. Income Tax and Depreciation Assumption

This section describes the calculation of the forecasted Federal Income Tax (FIT) and the associated deferred FIT and California Corporation Franchise Taxes ((CCFT) or state income tax) expenses.

PG&E estimates current FIT and CCFT on net operating income before income taxes. PG&E follows MACRS and Asset Depreciation Range⁴ guidelines for classifying capital additions and calculating federal and state tax depreciation. Current FIT expense forecast is the product of the currently effective corporate income tax rate (21 percent), and forecasted federal taxable income. Likewise, current state income tax expense is the product of the statutory rate (8.84 percent) and the forecasted state taxable income. The following tax adjustments are made to pre-tax book income and are common to the development of the federal and CCFT taxable income.

1) FIT Depreciation and CCFT Adjustment

Federal MACRS deductions are computed on a normalized basis. This allows PG&E to recognize the timing differences between book and federal tax deductions. This difference multiplied by the federal tax rate is called deferred FITs and is included as an adjustment to current federal tax expense and a credit to rate base. State income taxes are calculated using flowthrough treatment. With a flowthrough treatment, customers receive an immediate benefit from use of accelerated state tax deductions; there is no deferred state taxes and therefore no associated deduction to rate base.

³ D.23-01-002.

⁴ Uses Sum of Years Digits method.

2) FIT and CCFT Repair Deduction

Certain Electric Distribution or Generation Capital expenditures may qualify for the tax repair deduction. Both Federal and California tax repair deductions are treated on a flowthrough basis. In this proceeding, the Helms Uprate is ineligible for tax repair deduction due to capacity increase and major components replacement per the Internal Revenue Code (IRC) guidelines.

d. Property Taxes

Property tax calculations are determined by multiplying the forecasted taxable Plant Less Depreciation (Net Plant) by the composite property tax factor. The composite property tax factor is based on PG&E's 2023 GRC levelized average property tax factor for attrition years. The property tax factor is comprised of the adjusted base year market to cost ratio multiplied by the composite tax rate. The adjusted market to cost ratio is the relationship between the most current assessment (adjusted) and the taxable Net Plant.

e. Investment Tax Credit [James L. Higham]

The Inflation Reduction Act of 2022 (Act) provides incentives for green energy in the form of tax credits. Although some uncertainties exist regarding exactly how the statutory provisions of the Act will be interpreted by the Internal Revenue Service (IRS), the Act generally provides for a base credit of 6 percent, which can be increased by five times to 30 percent if the project meets the prevailing wage and apprenticeship requirements. PG&E's revenue requirements presented above assume that PG&E will receive the 30 percent bonus ITC rate for all Helms Uprate capital costs, except for interconnection costs.⁵

For ratemaking purposes, the realized ITCs will reduce the weighted average ratebase balance and, as a result, will reduce the return on ratebase in RO model revenue requirement calculations. The

⁵ Although the IRS had not issued final regulations as of November 30, 2023, proposed regulations have been issued as to how taxpayers will support the prevailing wage and apprenticeship requirements necessary to sustain an increased bonus ITC rate of 30 percent for qualifying investments. As described in Chapter 2, PG&E is putting into place processes that are intended to meet these proposed requirements.

1 accumulated ITC is amortized within the book life of the asset that
2 receives ITC treatment. In this way, customers will receive realized ITC
3 benefits over the life of the asset in the form of reduced rates associated
4 with a lower revenue requirement.

5 In Decision 93848, the Commission authorized the normalization of
6 ITCs to enable PG&E to remain fully eligible to claim ITC. The methods
7 of normalization are described in regulations issued by the IRS. PG&E
8 elected the method under IRC Section 46(f)(1). Section 46(f)(1)
9 requires a ratable amortization of ITC benefits to PG&E's non-regulated
10 earnings and a corresponding increase to rate base.⁶ PG&E follows the
11 IRC in this filing by computing the annual amortization of the ITC
12 reserve using the book future life expectancies of underlying Electric
13 Production -Hydroelectric assets based on what PG&E proposed in the
14 2023 GRC. Pursuant to IRS Private Letter Ruling 201230021, an ITC
15 that has not been monetized on a consolidated basis is ineligible as a
16 reduction to rate base. PG&E anticipates being able to monetize the
17 ITC either through a credit against PG&E's below the line shareholder
18 tax expense or by transferring all or a portion of the ITC to unrelated
19 third parties for cash.

20 In order to provide the Commission and stakeholders with additional
21 transparency about the actual value of the ITCs realized by PG&E and
22 passed on to customers for the Helms Uprate, PG&E proposes to
23 submit a Tier 1 Advice Letter if, at any time in the future, PG&E
24 determines that it will realize less than 30 percent ITC on any portion of
25 the capital cost of the Uprate, except for the interconnection costs. This
26 provides the Commission with the ability to continue its oversight of
27 PG&E's actions to obtain the anticipated ITC.

⁶ The unamortized balance of the ITC reserve is treated as a reduction to rate base, while the amortized portion increases the rate base.

1 **B. Proposal to Adjust Cost Recovery Cap through Future Advice Letters**
2 **[Rebecca R. Doidge]**

3 **1. Request to Adjust Cap Based on Identified Contingencies**

4 PG&E proposes an initial Cost Recovery Cap for the Helms Uprate
5 based on PG&E's Uprate Cost forecast of \$462 million. Since PG&E must
6 submit this Application early in the planning and design process in order to
7 combine the Uprate with the planned Lifecycle Replacement Work and
8 benefit from the ITC, PG&E has included reasonable contingency in its
9 Uprate Cost Forecast, as further described in Chapter 2. Nonetheless, there
10 remains a risk that due to certain factors largely outside of PG&E's control,
11 costs to implement the Helms Uprate will exceed PG&E's initial Cost
12 Recovery Cap. This section describes the two types of contingencies that
13 are most likely to lead to material cost increases and proposes regulatory
14 pathways to address any such realized contingencies to ensure
15 transparency and adequate opportunity for Commission review. Most
16 importantly, this proposal would provide an efficient way for the Commission
17 to make determinations on whether such increased costs are reasonable
18 such that the Uprate may proceed, if appropriate, without delays that could
19 jeopardize the key objectives of the project.

20 As a general matter, PG&E proposes that any increase in the Cost
21 Recovery Cap would require a full Commission disposition through either a
22 Resolution or a Decision. PG&E proposes to establish a memorandum
23 account (the Helms Uprate Memorandum Account (HUMA)) upon approval
24 of this Application that would be available to track any incurred costs that
25 exceed the Cost Recovery Cap. Costs recorded to the HUMA could only be
26 recovered in rates if they are subsequently authorized by the Commission
27 after a reasonableness review in a separate application.

28 However, for certain categories of contingencies, PG&E proposes that it
29 be authorized to seek an increase in the initial Cost Recovery Cap via a
30 Tier 3 Advice Letter, in order to provide timely, up-front review of these costs
31 and assurance of cost recovery if the project continues. Thus, any
32 Commission approval of such increased costs above the Uprate Cost
33 Forecast for these categories of contingencies would mean that these costs
34 do not need to be recorded to the HUMA and do not go through

1 after-the-fact reasonableness review. The categories of contingencies for
2 which an advice letter process would be available are: (1) costs associated
3 with Federal Energy Regulatory Commission (FERC) approvals; and
4 (2) Interconnection Customer's Interconnection Facilities⁷ costs associated
5 with interconnection requirements as determined pursuant to the California
6 Independent System Operator's (CAISO) tariff.

7 As described in Chapter 2, approvals from the FERC and
8 interconnection of the Helms Uprate capacity under the CAISO's tariff are
9 required. The ultimate scope, schedule, and cost of the Uprate are
10 dependent on the outcomes of these processes, which are in their very early
11 stages at the time of the filing of this Application. The requirements that
12 may result from the CAISO and FERC processes present significant
13 uncertainty to the Uprate, and PG&E will likely not know the extent of any
14 resulting delays or changes in scope for several years, as illustrated in the
15 timeline presented in Chapter 2. PG&E cannot wait to begin seeking
16 Commission authorization for cost recovery for the Uprate until after these
17 processes conclude because it would then be unable to make long lead-time
18 procurement commitments for the Project that are necessary in order to
19 combine the Uprate work with the planned Lifecycle Replacement Work, as
20 further described in Chapter 2.

21 In order to allow the Commission to review the reasonableness of the
22 current proposal while recognizing these significant uncertainties, PG&E
23 proposes that, if needed due to one of these two identified contingencies, it
24 be authorized in the final decision resolving this Application to seek an
25 adjustment to the Cost Recovery Cap through the submission of one or
26 more Tier 3 Advice Letters.

27 Only costs associated with one of the two identified contingencies above
28 would qualify for an advice letter filing. Any other cost increases would

7 The CAISO tariff defines Interconnection Customer's Interconnection Facilities as follows:

"All facilities and equipment, as identified in Appendix A of the Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the CAISO Controlled Grid. Interconnection Customer's Interconnection Facilities are sole use facilities." CAISO Tariff, App. A.

apply against the established Cost Recovery Cap and would be booked to the HUMA for after-the-fact reasonableness review if they cause exceedances in the approved Cost Recovery Cap.

**TABLE 4-2
PROPOSED CRITERIA FOR COMMISSION AND STAKEHOLDER REVIEW OF IDENTIFIED CONTINGENCIES**

Line No.	Method of Review	Criteria to Qualify	PG&E Submittal Requirements
1	Tier 3 Advice Letter to increase Cost Recovery Cap	Incremental forecasted costs are directly attributed to: 1) Interconnection Customer's Interconnection Facilities costs incurred pursuant to the CAISO Tariff; or 2) FERC license amendment requirements.	Documentation that new/additional scope is an outcome of either the CAISO interconnection study or the FERC license amendment order. Cost competitiveness showing that increased project cost is still competitive comparing its Net Market Value against then-current market prices for other long-duration energy storage options.
2	Separate Proceeding	Incurred costs above the Cost Recovery Cap that are not directly attributed to one of the two identified contingencies but instead are due to other general risk associated with project implementation—e.g., change in design due to unknown physical constraints, supply chain costs and delays, etc.	PG&E must record any incurred costs in excess of the approved Cost Recovery Cap to the HUMA and, if it seeks cost recovery of these incremental costs, must file a separate Application seeking reasonableness review of the incremental costs.

C. Cost Allocation [Erica Brown]

PG&E proposes to recover all above-market costs associated with the Helms Pumped Storage Plant, including costs associated with the Helms Uprate, through the Power Charge Indifference Adjustment (PCIA) rates via two separate vintages. The PCIA rate is authorized and implemented through the annual Energy Resource Recovery Account Forecast Proceeding. PG&E records billed PCIA revenues and authorized costs in the PABA vintage subaccounts. In the year the resource is forecast to become operational, PG&E would include the authorized revenue rate requirement in the PCIA Cost and Rate forecast and would establish PCIA rates to recover the authorized costs from bundled and non-exempt departing load customers.

1 First, PG&E proposes that costs associated with the extant capacity of
2 Helms continue to be recovered through the Legacy Utility Owned Generation
3 Subaccount, which records and recovers the costs associated with adopted
4 revenue requirements related to PG&E-owned generation installed before 2002
5 (“Legacy Utility-Owned Generation (UOG)”), including capital and related
6 non-fuel operating and maintenance expenses that began operation before
7 2002. The Helms facility currently qualifies for Legacy UOG treatment, which is
8 how PG&E currently records net above-market costs associated with the Helms
9 facility.

10 Second, PG&E requests that costs associated with the proposed
11 incremental capacity realized by the Helms Uprate be recovered via a new PCIA
12 vintage subaccount, the vintage of which would be determined based on the
13 year the generation resource construction begins.⁸

14 Because PG&E is proposing that this single facility be recovered through
15 two separate PABA subaccounts, it makes the following clarifications. First,
16 PG&E proposes that total project capital costs be recovered both through the
17 Legacy UOG vintage subaccount and through a new vintage subaccount,
18 prorated at an amount equal to the proportion of generation capacity within each
19 vintage as verified after end of construction through final testing. Second, PG&E
20 proposes that any revenues associated with operations be allocated between
21 the Legacy UOG vintage and the new vintage on a pro-rated basis equal to the
22 portion of total generation capacity within each vintage. In other words, while
23 the exact capacity additions are still subject to engineering review and will only
24 be finalized once construction is completed. For example, assume, *arguendo*,
25 that the incremental generation capacity added is on the lower end of the
26 possible range, say 150 megawatts (MW). When added to the extant generation
27 capacity of 1,212 MW, the expanded facility would have a total generation
28 capacity of 1,362 MW. When taken on a pro-rated basis equal to the portion of
29 total generation capacity within each vintage, 89 percent of all costs, both capital
30 and above-market operating costs, would be recovered through the Legacy
31 UOG vintage ($1,212 \text{ MW} / 1,362 \text{ MW} = 89\%$), while the remaining 11 percent of

⁸ More specifically, new vintage would be the later of: (1) the first date that expenditures are recorded will be capitalized once the project reaches commercial operation, or (2) the date the Commission approves the new resource for cost recovery.

costs would be recovered through the new vintage (150 MW/1,362 MW = 11%). PG&E believes this cost allocation approach fairly allocates costs to their source while remaining administratively simple.

D. Proposed Updates to Tariffs and Preliminary Statements to Implement Ratemaking Proposal [Ryan Stanley]

Under the proposal above, PG&E proposes minimal updates to tariffs or preliminary statements. Preliminary Statement HS, which outlines PABA, already includes the necessary details to govern all expected cost recovery as described above:

Under the Purposes, Preliminary Statement HS describes that “the PABA is comprised of subaccounts for each year’s vintage portfolio resources, that records the costs, market revenues, and imputed revenues of all generation resources executed or approved by the Commission for cost recovery that year. Amounts will include costs related to contracts executed with third parties and utility-owned resources.”

In addition, under Accounting Procedures section and after the approval of authorized revenue requirements in PG&E’s next GRC, PG&E would record the approved UOG authorized revenue requirement under line item 5.n., which includes “a debit equal to the annual authorized revenue requirements associated with PG&E’s owned generation divided by twelve” allocated between the Legacy UOG and new vintage subaccount on the generation capacity basis described in Section C above. Similarly, any CAISO market activity assignable to the Helms facility would be recorded to tariff lines 5.t. through 5.v. under the CAISO-Related Entries section, allocated on the generation capacity basis described in Section C above.

The only update PG&E recommends to Preliminary Statement HS is a clarification to the Accounting Procedures section, where it describes the two types of subaccounts, including the fact that the “Legacy UOG [vintage] includes PG&E’s hydroelectric and nuclear generation facilities.” PG&E proposes that the Commission require PG&E to file a Tier 1 Advice Letter to modify this description to articulate that the portion of PG&E’s Helms facility related to expanded capacity is subject to the future PCIA vintage. Since that vintage is not determinable until the first date of site-specific construction work, PG&E

1 recommends this compliance requirement be due 30 days after such
2 construction work has begun.

3 Consistent with the proposal for the HUMA in Section B, above, PG&E also
4 requests that it be allowed to establish the HUMA, if approved, via a Tier 1
5 Advice Letter.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX A
STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ERICA BROWN

Q 1 Please state your name and business address.

A 1 My name is Erica Brown, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of Energy Policy Analysis and Design. In this position, I am responsible for PG&E's position on a variety of energy policy topics including: regulations impacting energy procurement (e.g., Renewable Portfolio Standard, Resource Adequacy); valuation of distributed energy resources (e.g., Avoided Cost Calculator, Net Energy Metering); and portfolio planning, forecasting, and cost recovery (e.g., Energy Resource Recovery Account, Integrated Resource Plan).

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts in English Literature from New York University and a Master of Public Policy from the University of Michigan.

I have worked at PG&E for ten years where I have held a variety of energy policy roles. I started my career at PG&E as an Analyst working on California Independent System Operator market policy before switching to an Analyst position working on California Public Utilities Commission procurement policy. I subsequently moved into a leadership position and have held positions as Manager, Senior Manager, and now, Director working on energy policy and portfolio forecasting within the Energy and Procurement Policy Department at PG&E.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Application of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

- Chapter 4, "Ratemaking Proposal and Revenue Requirements":
 - Section C.

Q 5 Did you revise your prepared testimony?

A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance with a Ruling of the Administrative Law Judge. The only change was to remove prior references to Pacific Generation LLC as a co-applicant in the

1 Proceeding. I did not otherwise revise the prepared testimony, and in all
2 substantive respects it remains my testimony as of the December 20, 2023
3 original date of service.

4 Q 6 Does this conclude your statement of qualifications?

5 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF REBECCA R. DOIDGE

Q 1 Please state your name and business address.

A 1 My name is Rebecca R. Doidge, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Regulatory Consultant in PG&E's Generation Strategy and License Management team. In this role, I support PG&E's participation in various industry, federal, and state initiatives that have potential to affect PG&E's hydroelectric licenses. I also support PG&E's Land Conservation Commitment (LCC) by representing PG&E as the alternate Board Member on the Pacific Forest and Watershed Lands Stewardship Council.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Biology from Indiana University in 1998. I worked as an Environmental Consultant for several years before joining PG&E in 2006 as Project Manager for the LCC. Between 2009 and 2014, I held various leadership positions within PG&E's Environmental Management department, managing teams who support environmental permitting and compliance on large utility projects, as well as overseeing implementation of the environmental risk management program. In 2014, I rejoined the Power Generation team to manage a central program for performance improvement and, in 2017, I began supporting Generation's strategic planning program, leading a number of asset sale transactions which are part of the long-term strategy for PG&E's utility owned generation assets. In this role, I served as PG&E's witness on Section 851 applications supporting the asset sales, and as the witness for Energy Supply Ratemaking issues in the General Rate Case.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Application of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

- Chapter 4, "Ratemaking Proposal and Revenue Requirement":
 - Section B.

1 Q 5 Did you revise your prepared testimony?

2 A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance
3 with a Ruling of the Administrative Law Judge. The only change was to
4 remove prior references to Pacific Generation LLC as a co-applicant in the
5 Proceeding. I did not otherwise revise the prepared testimony, and in all
6 substantive respects it remains my testimony as of the December 20, 2023
7 original date of service.

8 Q 6 Does this conclude your statement of qualifications?

9 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAVID GABBARD

Q 1 Please state your name and business address.

A 1 My name is David Gabbard, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am PG&E's Vice President of Power Generation and I have been in a Vice President role since April 2023. I have worked at PG&E since 2005, holding a variety of leadership positions across the Engineering, Generation Interconnection, Project Management, Risk Management, Asset Strategy, Transmission Planning, and Transmission & Substation System Protection, Maintenance, and Construction.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from California Polytechnic State University, in 2006, and a Master's degree in Business Administration from the University of Pennsylvania Wharton School, in 2017.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Application of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

- Chapter 1, "Executive Summary and Overview."

Q 5 Did you revise your prepared testimony?

A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance with a Ruling of the Administrative Law Judge. The only change was to remove prior references to Pacific Generation LLC as a co-applicant in the Proceeding. I did not otherwise revise the prepared testimony, and in all substantive respects it remains my testimony as of the December 20, 2023 original date of service.

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KURT HANSEN

Q 1 Please state your name and business address.

A 1 My name is Kurt Hansen, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Chief Analyst in Energy Policy and Procurement Department. I work on a variety of policy and procurement projects, including the Helms Uprate Project.

Q 3 Please summarize your educational and professional background.

A 3 I have a Master of Science degree in Civil and Environmental Engineering, a Bachelor of Science degree in Physics, and a Bachelor of Business Administration degree. All three degrees are from the University of Wisconsin, Madison.

I joined PG&E in 2007 as a Principal Analyst. Before serving in my current role starting in 2023, I was the Director of Portfolio and Resource Forecasting and held other leadership roles in Energy Policy and Procurement, including in Portfolio Management and Market Design and Monitoring. Prior to joining PG&E, I was a self-employed consultant, implementing energy trading and risk management systems. Before that I worked at Henwood Energy Services providing energy consulting services focused on generation planning, resource procurement and regulatory issues.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in the Application of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

- Chapter 3, "Project Need, Benefits, and Cost-Effectiveness," except for Section C.2;
- Chapter 3, Attachment A, "PG&E's 2022 Integrated Resource Plan: Additional Procurement for Three Scenarios"; and
- Workpapers supporting Chapter 3, "Project Need, Benefits, and Cost-Effectiveness."

Q 5 Did you revise your prepared testimony?

1 A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance
2 with a Ruling of the Administrative Law Judge. The only change was to
3 remove prior references to Pacific Generation LLC as a co-applicant in the
4 Proceeding. I did not otherwise revise the prepared testimony, and in all
5 substantive respects it remains my testimony as of the December 20, 2023
6 original date of service.
7 Q 6 Does this conclude your statement of qualifications?
8 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JAMES L. HIGHAM, JR.

Q 1 Please state your name and business address.

A 1 My name is James L. Higham, Jr., and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Tax Senior Manager in the Tax Department within the Controller's organization at PG&E. In this position, I am responsible for overseeing the management of PG&E's federal and state income tax audits, as well as providing tax research and planning support on a variety of transactions, including the tax implications of the credits contained in the Inflation Reduction Act.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Fine Arts (Art History) from the College of William and Mary, Williamsburg, Virginia. I received a Juris Doctor from the University of Mississippi School of Law, Oxford, Mississippi. I received a Master's in Law (Taxation) from New York University School of Law, New York, New York. Since joining PG&E in April 1998, I have experienced increasing responsibilities within the Tax Department. Prior to my employment with PG&E, I was a Tax Manager at the accounting firm of KPMG Peat Marwick LLP in Los Angeles, California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Application of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

- Chapter 4, "Ratemaking Proposal and Revenue Requirements";
 - Section A.2.e.

Q 5 Did you revise your prepared testimony?

A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance with a Ruling of the Administrative Law Judge. The only change was to remove prior references to Pacific Generation LLC as a co-applicant in the Proceeding. I did not otherwise revise the prepared testimony, and in all substantive respects it remains my testimony as of the December 20, 2023 original date of service.

- 1 Q 6 Does this conclude your statement of qualifications?
- 2 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WILL OU

Q 1 Please state your name and business address.

A 1 My name is Will Ou, and my business address is Pacific Gas and Electric Company (PG&E or the Company), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Revenue Requirement Principal Analyst in Revenue Requirement and Cost Recovery and responsible for the financial analysis and modeling for incremental cost recovery filings and General Rate Cases (GRC). I also developed the Results of Operations models and calculated the revenue requirement forecast for multiple rate cases proceedings, for example, Wildfire and Gas Safety Cost, 2023 Wildfire Mitigation and Catastrophic Event.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor's degree in Accounting from Guangdong University of Foreign Studies, Guangzhou, China in 2011 and a Master's degree in Accounting from Golden Gate University, San Francisco in 2017. I joined PG&E in 2016 as a Capital Recovery Financial Analyst and was promoted to an Expert Financial Analyst in 2019. During my tenure in the Company's Capital Accounting Department, I supported multiple regulatory rate case proceedings including 2017 GRC and 2020 GRC and developed and calculated capital-related revenue requirements for separately funded projects. From December 2020 to June 2022, I worked as a Senior Consultant in KongBasileConsulting Company, supporting financial close and reporting, income tax and payroll tax compliance for multiple technology companies. In February 2023, I rejoined PG&E as a Revenue Requirement Expert Analyst, supporting the 2023 GRC Result of Operation Modeling and developing revenue requirement models for multiple incremental rate case proceedings.

Q 4 What is the purpose of your testimony?

1 A 4 I am sponsoring the following testimony and workpapers in the Application
2 of Pacific Gas and Electric Company to Recover Helms Uprate Costs:
3 • Chapter 4, "Ratemaking Proposal and Revenue Requirements":
4 – Section A;
5 • Workpapers supporting Chapter 4, Section A, "Revenue Requirement."
6 Q 5 Did you revise your prepared testimony?
7 A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance
8 with a Ruling of the Administrative Law Judge. The only change was to
9 remove prior references to Pacific Generation LLC as a co-applicant in the
10 Proceeding. I did not otherwise revise the prepared testimony, and in all
11 substantive respects it remains my testimony as of the December 20, 2023
12 original date of service.
13 Q 6 Does this conclude your statement of qualifications?
14 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CHARLES H. POST, JR.

Q 1 Please state your name and business address.

A 1 My name is Charles H. Post, Jr., and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal in the Commercial Procurement group of the Energy Procurement Department.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from the University of Virginia, with a Bachelor of Arts degree in 1989.

From 1989-1997, I worked for various law firms in Washington, D.C., supporting regulatory activities at the Federal Energy Regulatory Commission (FERC).

From 1997-1998, I worked for various law firms in San Francisco, California, supporting regulatory activities at the California Public Utilities Commission.

From 1998-2000, I worked for PG&E Energy Service in San Francisco, California, as a Market Development Analyst. My function was to open markets in Arizona in New York to allow PG&E Energy Services to provide retail services to customers in those states.

I joined PG&E as an employee in 2000, as a Senior Analyst in its Electric Transmission Rates organization supporting rate recovery at FERC for PG&E's transmission investments. I remained in that organization until 2004, when I moved to PG&E's Energy Procurement organization.

My roles in Energy Procurement focused on PG&E's efforts to meet its Renewables Portfolio Standard (RPS). My activities ranged from managing early RPS Request for Offers, to negotiating RPS agreements for both third-party and utility ownership, and managing the RPS Program. In March 2014, I transitioned to focus solely on PG&E's efforts to meet its Energy Storage obligations. My role was then expanded to cover PG&E's vehicle to grid integration efforts as well as PG&E's Demand Response Auction Mechanism activities.

1 In 2023, I rejoined the Commercial Procurement group to focus on
2 PG&E's procurement needs for both mandated programs as well as unique
3 pilot technologies and opportunities.

4 Q 4 What is the purpose of your testimony?

5 A 4 I am sponsoring the following testimony in the Application of Pacific Gas and
6 Electric Company to Recover Helms Uprate Costs:

- 7 • Chapter 3, Section C.2:
- 8 – Chapter 3, Attachment B, "Comparative Group"; and
- 9 – Chapter 3, Attachment C, "Independent Evaluator Report."

10 Q 5 Did you revise your prepared testimony?

11 A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance
12 with a Ruling of the Administrative Law Judge. The only change was to
13 remove prior references to Pacific Generation LLC as a co-applicant in the
14 Proceeding. I did not otherwise revise the prepared testimony, and in all
15 substantive respects it remains my testimony as of the December 20, 2023
16 original date of service.

17 Q 6 Does this conclude your statement of qualifications?

18 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JENNIFER L. SCOTT

Q 1 Please state your name and business address.

A 1 My name is Jennifer L. Scott, and my business address is Pacific Gas and Electric Company (PG&E), 33755 Old Mill Road, Auberry, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Strategic Agreement Consultant, Principal in PG&E's Power Generation Portfolio Strategy team. I am responsible for the development and implementation of generation portfolio strategies through evaluation of asset performance and economic modeling, which are part of the long-term-strategy for PG&E's utility-owned generation assets to achieve PG&E's goals on affordability, reliability, and supply. I conduct analyses of new generation opportunities including pumped storage, battery storage and capacity uprates. I lead the regulatory aspects of the Helms Uprate project, including the ratemaking application to the California Public Utilities Commission, the interconnection application to the California Independent System Operator Interconnection, and the license amendment application to the Federal Energy Regulatory Commission.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of California, San Diego in 2000; and a Master of Science degree in Mechanical Engineering from California State University, Fresno in 2003. I am a California Licensed Mechanical Professional Engineer. Prior to working at PG&E, I held engineering and project management positions within the hydroelectric industry. I began my career at PG&E in 2006 as a Hydroelectric Project Manager. Since then, I have held several positions with increasing responsibility in: engineering, project management, asset/risk management, operations and maintenance, and strategic planning. I have been in my current position since 2018.

1 Q 4 What is the purpose of your testimony?

2 A 4 I am sponsoring the following testimony and workpapers in the Application

3 of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

4 • Chapter 2, "Project Scope, Cost Forecast and Timeline":

5 – Chapter 2, Attachment A, "Hitachi Turbine Study";

6 – Chapter 2, Attachment B, "Hitachi Pump Study";

7 – Chapter 2, Attachment C, "Voith Generator Study";

8 – Chapter 2, Attachment D, "GE Rotor Study"; and

9 – Chapter 2, Attachment E, "Black and Veatch Feasibility Study."

10 • Workpapers supporting Chapter 2, "Project Scope, Cost Forecast and

11 Timeline."

12 Q 5 Did you revise your prepared testimony?

13 A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance

14 with a Ruling of the Administrative Law Judge. The only change was to

15 remove prior references to Pacific Generation LLC as a co-applicant in the

16 Proceeding. I did not otherwise revise the prepared testimony, and in all

17 substantive respects it remains my testimony as of the December 20, 2023

18 original date of service.

19 Q 6 Does this conclude your statement of qualifications?

20 A 6 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RYAN A. STANLEY

Q 1 Please state your name and business address.

A 1 My name is Ryan A. Stanley, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Manager in the Corporate Accounting Department within the Controller's organization at PG&E. In this position, I am responsible for overseeing and advising on cost recovery. I am also responsible for leading various reporting activities on the monthly accounting entries made into the Portfolio Allocation Balancing Account, in compliance with California Public Utilities Commission directives.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley. I received my Master's in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley.

I have over 17 years of regulated utility accounting, financial forecasting, and regulatory experience from having held positions of increasing responsibility at PG&E, in the Controller's and Regulatory Affairs organizations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in the Application of Pacific Gas and Electric Company to Recover Helms Uprate Costs:

- Chapter 4, "Ratemaking Proposal and Revenue Requirements":
 - Section D.

Q 5 Did you revise your prepared testimony?

A 5 Yes, I revised my prepared testimony on September 6, 2024, in compliance with a Ruling of the Administrative Law Judge. The only change was to remove prior references to Pacific Generation LLC as a co-applicant in the Proceeding. I did not otherwise revise the prepared testimony, and in all substantive respects it remains my testimony as of the December 20, 2023 original date of service.

- 1 Q 6 Does this conclude your statement of qualifications?
- 2 A 6 Yes, it does.