**DIABLO CANYON INDEPENDENT SAFETY COMMITTEE**

**Report on**

**Fact-Finding Meeting at DCPP**
**on September 16 and 17, 2025**

**by**
**Robert Budnitz and Richard McWhorter, Consultants**

**with**
**Raluca Scarlat, Member (Remotely Participating in Part)**

## 1.0 SUMMARY

The results of the DCISC September 16 and 17, 2025, Fact-Finding Meeting at the Diablo Canyon Power Plant (DCPP) in Avila Beach, CA, are presented. The subjects addressed and summarized in Section 3 are as follows:

1. Institute of Nuclear Power Operations Mid-Cycle Assessment
2. Unit 2 Power Reductions in Response to Area Wildfires
3. Single Point Vulnerability Program
4. Spent Fuel Canister Corrosion
5. Root Cause Evaluation for Auxiliary Saltwater Pump Motor Failure
6. Refueling Outage 2R25 Update and Safety Plan
7. Transmission Systems
8. Observe Readiness Review Board Meeting
9. Station Update
10. Discussions of Seismic Review Team Recommendations
11. Meet with DCPP Senior Director
12. Emergency Diesel Generators
13. Plant Tour

## 2.0 INTRODUCTION

This Fact-Finding Meeting at the DCPP was held to evaluate specific safety matters for the DCISC. The objective of the evaluation was to determine if Pacific Gas and Electric's (PG&E's) performance is appropriate and whether any areas revealed observations which are important enough to warrant further review, follow-up, or presentation at a public meeting. These safety matters include follow-up and/or continuing review efforts by the Committee, as well as those identified as a result of reviews of various safety-related documents.

Section 4 – Conclusions, highlights the conclusions of the Fact-Finding Team (FFT, Consultants Budnitz and McWhorter) based on items reported in Section 3 – Discussion. These highlights also include the FFT's suggested follow-up items for the DCISC, such as scheduling future Fact-Finding Meetings on the topic, presentations at future public meetings, and requests for future updates or information from DCPP on specific areas of interest, etc.

Section 5 – Recommendations, presents specific recommendations to the DCISC and PG&E proposed by the FFT. These recommendations will be considered by the DCISC. After review and approval by the DCISC, this Fact-Finding Report, including its recommendations, will be provided to PG&E. The Fact-Finding Report will also appear in the DCISC Annual Report.

## 3.0 DISCUSSION

### 3.1 Institute of Nuclear Power Operations Mid-Cycle Assessment

*(Because of its privacy agreement with DCPP, the DCISC cannot share information regarding the details of INPO and WANO evaluations or subsequent corrective actions.)*

The DCISC FFT met with Blair Jones, Chief of Staff and Director of Strategy, Performance Improvement (PI), Organizational Effectiveness, and Engagement; Karen Karner, Organizational Effectiveness Principal; Dan McBride, Operations Director; and Mark Frantz, Strategic Engineering Manager, for an update on the status of DCPP's recent Mid-Cycle Assessment performed as a part of regular reviews by the Institute of Nuclear Power Operations (INPO). The DCISC last reviewed the results of a site evaluation by the World Association of Nuclear Operators (WANO) during its November 2024 Fact-Finding Meeting (Reference 6.1), when it concluded the following:

*DCPP's August 2024 evaluation by the World Association of Nuclear Operators was positive overall.*

WANO is a sister organization to INPO and is generally responsible for plant reviews worldwide, whereas INPO concentrates on U.S. plants only. Both organizations' purpose is to help nuclear plants achieve and maintain excellence in nuclear operations. Each nuclear power plant in the U.S. nuclear industry is evaluated by INPO or WANO on its performance both continuously and with periodic focused site evaluations. The site evaluations are performed by external teams from INPO or WANO visiting the DCPP site every four years with a smaller "Continuum" site evaluation in the second year between the four-year evaluations. DCPP's most recent site evaluation, a WANO Peer Review, was completed in August 2024.

During the intervening years between site evaluations, DCPP performs a "Mid-Cycle Self-Assessment" to review overall plant performance and the status of corrective actions for Areas for Improvement (AFIs) identified during previous site evaluations. The DCPP staff briefed the FFT regarding the results of their recently completed Mid-Cycle Self-Assessment, which were generally positive overall. All the AFIs from the 2024 WANO evaluation were considered closed or recommended for closure, and two new Areas of Concern (AOCs) were opened. DCPP briefed the FFT on the nature of the AOCs which were generally aligned with the subject areas of several industry-wide performance improvement initiatives. The AOCs were entered into the Corrective Action Program to drive follow-up actions and their resolution prior to DCPP's next site evaluation, which will be an INPO Continuum site evaluation scheduled to be performed in late July and early August 2026.

**Conclusion: DCPP satisfactorily completed its Mid-Cycle Self-Assessment which was performed as a part of programs overseen by the Institute of Nuclear Power Operations.**

**Recommendations to the DCISC or PG&E: None.**

3.2 Unit 2 Power Reductions in Response to Area Wildfires

The DCISC FFT met with Dan McBride, Operations Director, for an update on two recent events at DCPP during which Unit 2's power levels were reduced in response to wildfires in the local area. This was the DCISC's first review of this event as a specific topic of review in a Fact-Finding Meeting.

As background, Mr. McBride described DCPP's 500kV offsite power transmission system which consists primarily of three power lines, one of which runs north from DCPP to the Gates Substation (about 79 miles away) and two of which run east in parallel to the Midway Substation (about 84 miles away). The three 500kV transmission lines provide for transmission of the plant's electric power output to the PG&E grid. (There are two additional 230kV transmission lines to the station, but those lines are used for providing a source of offsite power when units are offline or in startup operations and are not used for the export of the station's production power output to the grid.)

Important also to understand as a part of this topic was the Special Protection System (SPS) that was installed as a part of the transmission system protection scheme for the three 500kV lines connecting DCPP to the grid. The SPS was previously reviewed by the DCISC during its March 2020 Fact-Finding Meeting (Reference 6.2). The SPS was installed in 2006 following studies in the early 2000s by the Western Electricity Coordinating Council (WECC) which concluded that grid instabilities could occur if a two-unit DCPP trip occurred when two of three 500kV lines connecting DCPP to the grid were out of service. To prevent this potential instability, the SPS was installed to activate when the total output of both DCPP units was greater than 1,700 MWe, and, when activated, served to trip one of the DCPP units if two of the three transmission lines tripped offline or were otherwise removed from service.

Mr. McBride described to the FFT the overall sequence of events that led to the first of two power reductions on Unit 2. On about July 4, 2025, elements of the Madre Fire in southeast San Luis Obispo County threatened to expand to an area underneath the two 500kV lines running to the Midway substation. PG&E decided to reduce power on Unit 2 to a level which made total station output less than 1,600 MWe (approximately 47% reactor power). The 1,600 MWe value was selected based on established guidance for plant operation during a loss of two 500 kV transmission lines which was contained in DCPP Procedure OP J-2:VIII, "Guidelines for Reliable Transmission Service for DCPP," Revision 42, dated December 24, 2024, a copy of which was reviewed by the FFT. This was a conservative decision made to preclude the possibility that a unit would be tripped by the SPS if the Madre Fire damaged and caused a trip of both the two 500kV lines to Midway. The power reduction lasted about two days, after which the Madre Fire was deemed to no longer threaten damage to the two 500kV lines and Unit 2 was returned to full power.

The second power reduction on Unit 2 began on August 4, 2025, when the Gifford Fire threatened the two 500kV lines to Midway. The Gifford Fire was a fast-moving fire that started about five miles away from the two 500kV lines. PG&E staff promptly decided to again reduce power on Unit 2 to a level that made total station output less than 1,600 MWe. This was again a conservative decision made to preclude the possibility that a unit would be tripped by the SPS if the Gifford Fire damaged and caused a trip of both the two 500kV lines to Midway. In this case, the Gifford fire did expand to the area under the two 500kV lines to Midway and PG&E's Grid Control Center took the two lines out of service for several days to preclude the possibility of an automatic trip of the lines caused by fire damage. The fire remained active and the two 500kV lines remained out of service for an extended time. Following containment of the fire along with inspection and re-energization of the two 500kV lines, Unit 2 was returned to full power 11 days later.

The FFT inquired about the process for making the decision to reduce power on Unit 2 in response to the fires. Mr. McBride reported that station leadership regularly participated in corporate conference calls that were held during wildfire events. Those conference calls were held twice daily and included various PG&E divisions including DCPP, the Grid Control Center, the Transmission Group, and the Hazard Awareness Warning Center. The Hazard Awareness Warning Center is a PG&E group that monitors natural disasters (wildfires, earthquakes, tsunamis, weather, etc.) and their potential impacts to PG&E's assets and customers. During such situations, it gathers real-time information from multiple external sources and provides that information to a range of internal and external stakeholders. It was during these conference calls that DCPP's leaders discussed the risks from the fires to the 500kV power lines with the other corporate entities and collaboratively decided that the prudent and conservation action would be to reduce power on one of the DCPP units. Reducing power on one unit would put total station output below that needed for SPS actuation and eliminate the risk of an automatic DCPP unit trip if two of the 500kV lines were lost. In response to the FFT's questions, Mr. McBride reported that normal (slow) ramp rates were used for the power changes which generally took about three hours to accomplish. He also reported that there were no significant equipment problems that occurred during any of the power changes. The FFT concluded that DCPP's proactive responses to the wildfires were appropriate and reflected a conservative approach by station leadership in making major decisions.

**<u>Conclusions</u>: DCPP twice took action to reduce Unit 2 power levels to preclude the possibility of incurring an automatic unit trip initiated by the Special Protection System if multiple 500kV transmission lines were lost during local wildfire events. The DCISC found that these proactive decisions, which were initiated by DCPP, were appropriate and reflected a conservative approach by station leadership in making major decisions.**

**<u>Recommendations to the DCISC or PG&E</u>: None.**

### 3.3 <u>Single Point Vulnerabilities</u>

The DCISC FFT met with Mark Baker, Engineering Programs Supervisor, and Dallas Adams, Engineering Programs Manager, for an update on DCPP's program for identifying and managing Single Point Vulnerabilities (SPVs). Delphine Hou, Harpreet Bhalla, and Jerry Bischof from the California Department of Water Resources (DWR) participated remotely in the meeting. The DCISC last reviewed this item in August 2025 (Reference 6.3), when it concluded the following:

> *DCPP has completed major changes to its program for managing Single Point Vulnerabilities in accordance with industry guidelines. These changes were implemented in a manner that maintained adequate controls to ensure high levels of reliability for critical components. DCPP initiated a new Notification requesting benchmarking single point vulnerability programs at other reactor plants. This is a positive, proactive move.*

DCPP first studied this issue in 2002 in order to identify and eliminate SPVs at a system and component level. At that time, a single component would be classified as an SPV component if its failure (alone) could result in a reactor trip or turbine trip, or a plant decrease in power of greater than 2% power. In 2006, DCPP began a more extensive SPV study on all systems (about 20) that had an impact on either generation or reliability and completed it in 2008. In the 20 reviewed plant systems, over 1,500 SPVs were identified and evaluated for the two units (over 750 for each individual unit). This was a collaborative effort with support from industry organizations such as the Electric Power Research Institute (EPRI) and the Nuclear Energy Institute (NEI). As a result of these studies, actions were initiated on some SPVs to eliminate them by modifications and/or to minimize or eliminate their failure rate by changes in Preventive Maintenance (PM) practices. By 2015, all of these actions had been completed and all SPVs were considered mitigated either through modifications or adequate maintenance practices.

In 2016, DCPP made changes in the SPV program as outlined in Nuclear Energy Institute issued Efficiency Bulletin (EB) 16-25, "Critical Component Reduction," excluding some categories of components that had previously been considered as critical. In 2017, DCPP revised its program guidance contained in procedure ER1.DC1, "Component Classification," to conform to the guidelines of the EB. Then, it undertook a review of all components previously classified as critical in the plant's SAP database system to determine the needed classification code changes. The SAP database served to contain and manage all component classification codes as well as the applicable Preventative Maintenance tasks and schedules. The resulting recommended classification code changes were further reviewed and approved by the applicable System Engineers and the Plant Health Committee prior to implementation. The review resulted in a reduction in the number of components classified as SPVs from over 1500 to 931.

Mr. Adams reviewed the history of DCPP's SPV program with the FFT and discussed the various station procedures that continuously govern ongoing elements of the program. He reported that since the 2017 efforts, the SPV program had remained essentially unchanged at DCPP, and the station was not currently focused on the elimination of any remaining SPVs. Instead, the industry and station were focused on taking broader, more significant approaches to improve Equipment Reliability overall. Current initiatives include a recent revision to the Institute of Nuclear Operations (INPO) Industry Event Report (IER) 21-04, "Improving Plant Reliability," and World

Association of Nuclear Operators (WANO) Significant Operating Event Report (SOER) 25-01, "Improving Equipment Reliability in Nuclear Facilities." DCPP's responses to these industry initiatives were in progress and would include benchmarking the status of SPV programs at other stations in early 2026 (tracked by Notification 5129756). Lessons learned from that benchmarking would be incorporated into the establishment of a comprehensive Equipment Reliability strategy as a part of the station's submission of formal responses to the industry-wide Equipment Reliability initiatives later in 2026.

**Conclusion: DCPP's Single Point Vulnerability Program was being managed well under plant processes and procedures, and it is now considered a part of DCPP's broader programs to foster high Equipment Reliability.**

**Recommendations to the DCISC or PG&E: None.**

3.4 Spent Fuel Canister Corrosion

The DCISC FFT met with Philippe Soenen, Strategic Initiatives Director; Eric Bracken, Manager Dry Fuel Storage; and Kyle Duke, Supervisor, Dry Fuel Management Program, for an update on DCPP's program for identifying and managing corrosion of Multi-Purpose Canisters (MPCs) used to store spent fuel at the Independent Spent Fuel Storage Installation (ISFSI). DCISC Consultant Ferman Wardell and Counsel Robert Rathie remotely participated in this meeting. The DCISC last reviewed this item in July 2025 (Reference 6.4), when it concluded the following:

> *DCPP had developed the first draft of responses to concerns by a member of the public at the July 2025 DCISC Fact-finding meeting and will provide final responses at the September 2025 DCISC Fact-finding Meeting.*

In early 2025, the DCISC received an inquiry from a member of the public regarding DCPP's planned follow-up activities for an inspection performed in early 2021 of MPCs stored at the DCPP ISFSI. The 2021 MPC inspections were performed as a part of a larger effort to inspect several structures and pieces of equipment at the ISFSI to support DCPP's application for ISFSI License Renewal under 10 CFR 72.42 for 40 years. The inspection results were contained in Appendix E, "Pre-Application Inspection Report," to the ISFSI License Renewal Application submitted to the NRC on March 9, 2022 (Reference 6.5), and the ISFSI License Renewal was approved by the NRC on June 20, 2025. In response to the inquiry, DCISC member Peterson, Consultant Wardell, and counsel exchanged correspondence and met remotely to discuss the questions which centered around technical details regarding the adequacy of the 2021 MPC inspections and plans for future inspections. As a result of the discussions, the DCISC requested the inquiring individual provide written questions that would be appropriate for the DCISC to request PG&E to evaluate and provide responses.

The inquiring individual provided their questions to the DCISC in June 2025, and the DCISC forwarded the questions to PG&E in July 2025. At that time, PG&E promised to respond by the date of this September Fact-Finding Meeting, and the initial responses were received by the DCISC on September 12, 2025.

During this meeting, the FFT reviewed PG&E's initial responses and requested several points of clarification be provided, particularly with regards to the qualification of inspection probes, probe calibration records, and plans for the next round of inspections planned to be performed during 2026. PG&E agreed to revise the responses to include the additional information, and they provided revised responses to the DCISC on October 7, 2025. Unfortunately, the revised responses were not provided in time for review and the inclusion of the DCISC's evaluations into this report. Accordingly, the FFT recommends that the DCISC follow up with additional review of PG&E's revised responses to questions and concerns regarding methods used to inspect Independent Spent Fuel Storage Facility Multi-Purpose Canisters for corrosion. The questions and PG&E's revised responses are included in this report as Enclosure 1.

**<u>Conclusions</u>: DCPP provided responses to questions and concerns received by the DCISC from a member of the public regarding methods used to inspect Spent Fuel Multi-Purpose Canisters for corrosion. Additional information was requested during this Fact-Finding Meeting and later provided by PG&E. The DCISC should review this revised information during a future Fact-finding Meeting.**

**<u>Recommendation for the DCISC</u>: The DCISC should follow up at a future Fact-Finding Meeting with additional review of PG&E's revised responses to questions and concerns regarding methods used to inspect Independent Spent Fuel Storage Facility Multi-Purpose Canisters for corrosion. (D9/25FF-3.4)**

**<u>Recommendations to PG&E</u>: None.**

### 3.5 <u>Root Cause Evaluation for Auxiliary Saltwater Pump Motor Failure</u>

The DCISC FFT met with Blair Jones, Chief of Staff and Director of Strategy, Performance Improvement (PI), Organizational Effectiveness, and Engagement; John Covey, PI Manager; Colt Wells, PI Supervisor; Dennis Hammond, Senior Advising Performance Improvement Coordinator; and Ken Pazdan, General Maintenance Manager, to review the status of the Cause Evaluation and corrective actions for a failure of the motor on Auxiliary Saltwater (ASW) Pump 2-2 in the fall of 2023. Harpreet Bhalla, and Jerry Bischof from the California Department of Water Resources (DWR) participated remotely in the meeting. The DCISC last reviewed the status of this Cause Evaluation during its April 2025 Fact-Finding Meeting (Reference 6.6), when it concluded the following:

> *PG&E was continuing to evaluate why procedure changes made as a result of a 2018 Root Cause Evaluation for an Auxiliary Saltwater Pump motor bearing failure were not sufficiently effective to prevent the recurrence of a similar issue in 2023.*

As reviewed by the DCISC in March and May 2024, examinations following removal of the failed ASW Pump 2-2 motor in 2023 revealed that the motor bearing was degraded with wear patterns the same as a motor bearing degradation that occurred in November 2018 on the motor for ASW

Pump 2-1. In 2018, a Root Cause Evaluation (RCE) was performed and the cause of the 2018 bearing degradation was determined to be excessive axial pre-loading (thrust) of the bearing when it was reassembled following motor overhaul in 2016. During its November 2024 review of the Cause Evaluation, the DCISC inquired about how DCPP dispositioned the 2018 RCE's ineffectiveness in preventing recurrence of the bearing failure. DCPP provided a copy of a Notification (SAPN 51225061, "Inadequate Root Cause CA Implementation") which addressed the question. The FFT reviewed the Notification and concluded that the information provided did not fully address the issue. Following the November 2024 Fact-Finding Meeting, PG&E explained that the Notification was still open and evaluations were still in progress to determine the final corrective actions. As a result, the DCISC made the following recommendation to PG&E:

> *PG&E should continue to evaluate why a 2018 Root Cause Evaluation for a failed Auxiliary Saltwater Pump motor bearing did not result in sufficiently effective procedure changes. (P11/24FF-3.11)*

The purpose of this meeting was to review details of the above recommendation and any actions taken by PG&E since the November 2024 review. The DCPP staff reported that additional reviews of what went wrong during implementation of corrective actions for the 2018 RCE were completed and the Corrective Action Program (CAP) processes had been changed. Specifically, in the future when a procedure change was recommended as a corrective action in an RCE, the resulting proposed change would be required to be reviewed and approved by a member of the team originally performing the RCE to ensure that the procedure change was sufficient to correct the problem as stated in the RCE. The FFT was provided with a copy of the updated Notification (SAPN 51225061) and verified that task 21 of the Notification implemented the process change as discussed with the FFT. The FFT concluded that appropriate corrective actions had been taken, and the DCISC's recommendation to PG&E should be closed.

**<u>Conclusion</u>: PG&E completed evaluations regarding why procedure changes made as a result of a 2018 Root Cause Evaluation for an Auxiliary Saltwater Pump motor bearing failure were not sufficiently effective to prevent the recurrence of a similar issue in 2023, and appropriate changes to the Corrective Action Program were initiated.**

**<u>Recommendations to the DCISC</u>: None.**

**<u>Recommendation to PG&E</u>: The following previous recommendation to PG&E was reviewed in this Fact-Finding Meeting and is recommended for closure: *PG&E should continue to evaluate why a 2018 Root Cause Evaluation for a failed Auxiliary Saltwater Pump motor bearing did not result in sufficiently effective procedure changes (P11/24FF-3.11)*.**

### 3.6 <u>Refueling Outage 2R25 Update and Safety Plan</u>

The DCISC FFT met with Casey Weir, Outage Manager, for an update on preparations for the upcoming Refueling Outage 2R25. Delphine Hou, Harpreet Bhalla, and Jerry Bischof from the California Department of Water Resources (DWR) participated remotely in the meeting. The

DCISC last reviewed outage preparations during its March 2025 Fact-Finding Meeting (Reference 6.7), when it concluded the following:

> *DCPP's preparations for Refueling Outage 1R25 and the retrieval of Reactor Vessel neutron embrittlement sample Capsule B appeared to be progressing satisfactorily.*

Refueling Outage 2R25 was planned to begin in early October 2025 with a planned duration of 40 days. Mr. Weir provided an overview of outage preparations. He reported that preparations were generally on track, and there had been no major changes to the outage scope or schedule. Onboarding was beginning for the approximately 1000 supplemental staff expected to work at DCPP during the outage. The outage schedule showed less overall duration than the goal of 40 days, and the critical path of the schedule ran through the refurbishment of the Unit 2 Main Turbine as was performed on Unit 1 during Refueling Outage 1R25. Other major projects planned for completion during Refueling Outage 2R25 included replacement of the Digital Rod Position Indication System and refurbishments to several secondary plant systems. He reported that there were no major supply chain issues at the time of the meeting. Goals for the outage were as follows:

| Performance Measure | Goal |
|---|---|
| Recordable Injuries | 0 |
| Serious Injury or Fatality Events | 0 |
| Nuclear Safety Events | 0 |
| Site Human Performance Clock Resets | 0 |
| Foreign Material Exclusion Events | 0 |
| Outage Duration (Days) | < 40 |
| Radiation Dose (Person-Rem) | < 30 |
| Power Ascension (Days) | < 5 |
| Reliability (Days Following Outage) | > 90 |

At the FFT's request, Mr. Weir provided an overview of the Refueling Outage 1R25 Outage Safety Plan and Safety Schedule and provided copies of the draft plan and schedule to the FFT. The preparation and use of the Outage Safety Plan and Safety Schedule were governed by DCPP procedure AD8.DC50, "Outage Safety Management," Revision 5A, dated July 7, 2022, and AD8.DC55, "Outage Safety Scheduling," Revision 50, dated March 3, 2025, copies of which were previously provided to the DCISC. The purpose of the plan and schedule was to provide information on outage safety requirements and highlight potential higher risk activities to plant staff. A key element of the Outage Safety Plan was the Defense-in-Depth Chart. DCPP uses "Phoenix," a computer-based tool used online to analyze changes in risk using the Probabilistic Risk Assessment (PRA) model when equipment is removed from service for maintenance. As the PRA model does not extend to shutdown conditions, Phoenix is used during outages via the loading of deterministic fault trees for shutdown conditions based on the Outage Safety Checklists and generating a set of color-coded status indicators for shutdown conditions. An "N+1" Defense in Depth (DID) approach, where N generally represents the minimum number of equipment sets needed to maintain a key safety function, is then utilized by Phoenix to evaluate the availability of the key safety functions. DCPP considers a status of Green or Yellow as acceptable for planned outage activities because key safety functions are fully supported with at least N+1 DID.

Contingency plans provide an additional approach to DID, because they provide a backup safety function should a minimum safety function become unavailable. The draft Refueling Outage 2R25 Safety Schedule discussed with Mr. Weir contained no Orange or Red (less than N+1 DID) conditions and three individual Yellow ones. The three planned Yellow conditions included those that were typical of any refueling outage, and there were no significant concerns identified in the Safety Plan or Safety Schedule. There was one infrequently performed evolution that would be required when the 230kV offsite power supplies to both units were to be taken out of service in order to replace disconnect switches in the 230kV switchyard. During that time, offsite power would continue to be provided via the 500kV transmission system which was an alternate alignment approved for short time periods.

**<u>Conclusion:</u> DCPP's preparations for Refueling Outage 2R25 appeared to be progressing satisfactorily.**

**<u>Recommendations to the DCISC or PG&E:</u> None.**

### 3.7 <u>Transmission System</u>

The DCISC FFT met with Vo Do, Transmission System Engineer, and Steve Fost, Strategic Engineering Supervisor, for an update on the health of DCPP's Transmission System. The DCISC last reviewed this topic during its December 2022 Fact-Finding Meeting (Reference 6.8), when it concluded the following:

> *The 230kV and 500kV Transmission Systems are both rated in Green health, which is good. Minor on-going problems are being addressed using the Corrective Action Program. DCPP plans to move its spare transformers up the hill near the Independent Spent Fuel Storage Installation to get them out of the salt spray environment. Reviews of maintenance and equipment upgrades are under way for license extension.*

Mr. Vo briefed the Fact-Finding Team on the health of the 500kV and 230kV Switchyards and the power lines connecting DCPP to the transmission grid. The 500kV System is a DCPP Tier 1 Level System, meaning it is of highest relative significance and requires a periodic system health report, and the 230kV System is a Tier 2 Level System, for which no formal system health report is generated. Three 500kV and two 230kV transmission system connections form both a path for electricity generated by DCPP to reach transmission system loads and a path for electricity to be supplied to one or both units when shut down. The 500kV system is the normal path for station electrical output to the grid and supplies station input power when a unit is online or the 230kV system is unavailable. The 230kV system is DCPP's normal source of offsite electrical input power when a unit is offline. DCPP's 230kV system is served by PG&E's offsite 230kV system through two incoming lines to the DCPP switchyard. The 230kV system then connects to DCPP's vital buses through the station's Startup Transformers. Any of the station's three 500kV offsite power lines can also serve as a backup offsite power source if needed due to a 230kV outage. The station's Emergency Diesel Generators (EDGs) serve as the ultimate backup if the 230kV and 500kV systems are both unable to perform their functions.

Mr. Vo provided copies of the 500kV system health reports to the FFT and reviewed their status. The Unit 1 500kV System Health Report had a Green color overall and Green colors for all sub-indicators (26 total) for the second quarter of 2025 noting two minor problems with broken insulator sections. The Unit 2 500kV System Health Report had a Green color overall with one issue challenging system health and driving 1 of 26 sub-indicators into the White (Needing Improvement) category for the second quarter of 2025. The white sub-indicator was related to ongoing efforts to reduce the vulnerability of insulators to contamination from the deposition of minerals carried airborne in the coastal environment. Unit 2 also had minor problems with broken insulator sections in the 500kV system. On all the broken insulators, the minimum requirements for the number of intact insulators and insulator lengths continued to be met by a wide margin. Some of these failures were detected and evaluated via periodic inspections of transmission system lines and towers conducted via remote camera drones. Mr. Vo reported that these minor failures were typical of insulators throughout the PG&E system, and there were thousands of individual insulators at DCPP. Additionally, he noted that phase three of a four-phase major transmission system project to replace all the analog relays in the 500kV switchyard with digital relays would be implemented in the 500kV switchyard during Refueling Outage 2R25.

Regarding the 230kV Transmission Systems on both units, he reported that both units were in good health; however, there was no formal system health report as explained above. During the 1R26 and 2R26 Refueling Outages, a major project to replace breakers in the 230kV switchyard with updated breakers containing $SF_6$ would be implemented along with a project to upgrade the 230kV switchyard with digital relays.

The FFT inquired if DCPP had experienced any recent issues with grid stability, and Mr. Vo reported that none had occurred that affected the plant. From the plant's perspective, the 500kV system had been free from instabilities. On the 230kV system, occasional high voltage situations occurred and these were addressed by actions taken by the Grid Control Center. Low voltage situations on the 230kV system were addressed by the operation of capacitor banks located at DCPP in the 230kV switchyard.

The FFT also discussed with Mr. Vo a question raised by a member of the public at the DCISC's February 2025 Public Meeting regarding the differences between traditional electric generators and non-traditional/renewable electric power generators with regards to 'Grid Inertia.' He noted that 'Grid Inertia' is an informal term used to describe the transmission system's natural reluctance to change voltage or frequency in response to short duration perturbations. In general, traditional electric plants with large heavy spinning generators provide a physical damping effect on the transmission system in the form of a reluctance to change voltage or frequency quickly. Non-traditional, renewable generators tend to control voltage and frequency using digital/electronic equipment which do not provide a similar physical damping effect. The massive rotating turbines in nuclear plants provide essential kinetic energy storage that naturally resists frequency disturbances, giving grid operators critical time to respond to imbalances. When these plants shut down, the system's ability to resist further instability is significantly reduced, making the grid more vulnerable to cascading failures and blackouts.

As Spain's April 28, 2025, blackout demonstrated, maintaining adequate system inertia is crucial for grid stability, particularly as power systems evolve toward higher penetrations of renewable energy. The heavy turbines in nuclear plants represent one of the most effective sources of grid inertia available, making their role in grid stability increasingly important as conventional thermal generation is retired

**Conclusions: The 230kV and 500kV Transmission Systems at DCPP were both in good health with no major issues. Projects are being implemented to upgrade breakers and relays in the DCPP switchyards.**

**Recommendations to the DCISC or PG&E: None.**

### 3.8 Observe Readiness Review Board Meeting

The DCISC FFT observed a Readiness Review Board (RRB) Meeting. This was the DCISC's first observation of this particular type of meeting although it regularly observes outage maintenance planning meetings such as its observations in May 2025 (Reference 6.9) when it concluded the following:

> *The May 8, 2025, meeting of the Outage Scope Review Team and Daily Notification Review Team was conducted efficiently and effectively. The team appropriately reviewed and dispositioned approximately 40 Notifications from the previous shift.*

This RRB meeting was facilitated by Jeremy Goff, Secondary Systems Outage Windows Manager, and its purpose was to review the scheduling and sequence of outage windows during secondary plant shutdown at the start of the upcoming Refueling Outage 2R25 and secondary plant startup at the end of the outage. All the major departments at the station were represented, and attendees focused on ensuring that the window sequences were efficient and that all precursor events were properly identified and scheduled. The FFT found the meeting to be well facilitated and the discussions were open and appeared to be effective.

**Conclusions: A September 16, 2025, Readiness Review Board meeting was conducted efficiently and effectively. Representatives from various departments focused on ensuring that outage secondary system shutdown and startup activities were appropriately scheduled.**

**Recommendations to the DCISC or PG&E: None.**

### 3.9 Station Update

The DCISC FFT met with Mike Brass, Maintenance Services Director, for a Station Update, and DCISC Member Dr. Raluca Scarlat participated remotely. The DCISC last received a Station Update during its July 2025 Fact-Finding Meeting (Reference 6.10), when it concluded the following:

*The plant status and operating update since the previous DCISC Fact-finding meeting was informative and useful.*

Mr. Brass provided an update on the following recent activities at DCPP as follows:

- Power Production – Unit 1 has operated at 100% power and has had no major issues or power reductions since startup following Refueling Outage 1R25 in the spring of 2025. Unit 2 power was reduced twice this summer to about 47% in response to area wildfires (see Section 3.2 of this report).

- Preparations for Refueling Outage 2R25 – Station activities were currently focusing on completing all preparations for the upcoming Unit 2 outage which was scheduled to begin about 17 days following this Fact-Finding Meeting. He briefed the FFT on changes that were being made in how the station would perform the planned refurbishment of the Unit 2 High-Pressure Turbine to be better prepared for dealing with significant amounts of internal erosion like that which were discovered during similar work on Unit 1 in the spring of 2025. The Unit 1 turbine refurbishment issues were reviewed by the DCISC during its April 2025 Fact-Finding Meeting (Reference 6.11)

- Major Maintenance Activities – Over the last few months since the completion of Refueling Outage 1R25, DCPP completed three major Maintenance Outage Window (MOW) activities to perform preventive and corrective maintenance on Unit 2's three Emergency Diesel Generators. He described several issues discovered during post-maintenance testing which were also discussed when reviewing the health of EDG systems later in this Fact-Finding Meeting (see Section 3.12 below). Mr. Brass also reported that there had been no major human performance issues at the station over the last few months.

**<u>Conclusion</u>: DCPP's update on recent station activities was informative, and no new major issues were identified.**

**<u>Recommendations to the DCISC or PG&E</u>: None.**

3.10 <u>Discussions of Seismic Review Team Recommendations</u>

On August 19, 2025, DCISC Seismic Review Team (SRT) Consultant Dr. Michael Oskin joined a field trip with PG&E staff and members of the California Public Utilities Commission Independent Peer Review Panel to view evidence for uplift, folding, and river incision into the Orcutt Formation, a widespread sedimentary deposit mantling that region. Dr. Oskin's observations of his meeting, provided by him as information input to the SRT, are included in this report as Enclosure 2.

On September 10, 2025, DCISC Member Dr. Najmedin Meshkati, Consultants Andrew Kadak and Richard McWhorter, and the three members of the DCISC's SRT (Drs. Thomas Jordan, Michael

Oskin, and Scott Marshall) met in-person and remotely with PG&E to discuss the nine recommendations made to PG&E by the SRT in their report, "Review of the Bird Critique," dated May 30, 2025, presented and endorsed at the DCISC's June Public Meeting (Reference 6.12). The following PG&E staff and consultants were present at the meeting: Jeff Bachhuber, Director, Geosciences; Albert Kottke, Principal Geotechnical Earthquake Engineer; Chris Madugo, Geosciences Consultant; Jearl Strickland, Consultant (PG&E); Robbie Thorson, Licensing Renewal Engineer; and Steve Thompson and Jeff Unruh, Consultants with Lettis Consultants International, Inc.

The purpose of the September 10, 2025, meeting (which was requested by PG&E) was to provide PG&E an opportunity to ask questions and receive additional information from the SRT regarding its May 2025 report and the nine recommendations for PG&E contained therein. The following general topics, as requested by PG&E, were discussed during that meeting:

- The DCISC's plans to incorporate the SRT recommendations as recommendations from the DCISC to PG&E in its upcoming 35th Annual Report.
- Geology of the Southwest Boundary Zone area and evidence for the SRT's interpretations of available geologic data
- Possible effects of the SRT's interpretations of the geologic data upon fault hazard modeling for the Southwest Boundary Zone
- Weightings used to evaluate the Southwest Boundary Zone model against other area fault models
- Currently available techniques for expanding the use of wide area geodetic data to supplement individual nearby fault data and models
- The relationship between the research recommended by the SRT and PG&E's Long-Term Seismic Program
- Observations from the August 19, 2025, field trip (attended by SRT member Dr. Oskin) to view geologic features near the Orcutt Formation
- The possibility of publishing the SRT's findings as a more traditional academic research paper

On September 17, 2025 (during this Fact-Finding Meeting), the FFT (DCISC Consultants Dr. Robert Budnitz and Richard McWhorter) met in-person and remotely with PG&E to discuss the nine recommendations made to PG&E by the SRT. Delphine Hou, Harpreet Bhalla, Deb Luchsinger, and Jerry Bischof from the California Department of Water Resources (DWR) participated remotely in the meeting. The following PG&E staff were present at the meeting: Philippe Soenen, Strategic Initiatives Director; Jeff Bachhuber, Director, Geosciences; Albert Kottke, Principal Geotechnical Earthquake Engineer; Chris Madugo, Geosciences Consultant; and Jearl Strickland, Consultant (PG&E). The following general topics were discussed:

- Significance of the SRT's recent interpretations of the geologic data upon past fault hazard modeling for the Southwest Boundary Zone
- Weightings used to evaluate the Southwest Boundary Zone model against the Hosgri and other area fault models

- Relative significance of the Southwest Boundary Zone model versus the Hosgri Fault model in determining the overall hazard to the DCPP site and impact on power plant structures
- The relationship between the research recommended by the SRT and PG&E's Long-Term Seismic Program
- PG&E's tentative plans for evaluating the nine SRT recommendations with regards to significance and priority.

One important technical observation that emerged from the discussion concerned the relative importance to overall seismic hazard at the DCPP site of the Hosgri Fault system compared to the seismic sources associated with the Southwest Boundary Zone. [As noted in the SRT's May 30, 2025, report to the DCISC (Reference 6.12), *"The SWBZ includes the San Luis Bay fault, Rattlesnake fault and Olson fault in the west, closest to DCPP, and the Wilmar Avenue fault, Los Berros fault, and Oceano fault in the east, offshore of Pismo Beach."* With reference to this statement the SRT observes that it is "following the definition established by PG&E".]

An important part of the discussion in this Fact-Finding session, and indeed in the SRT's analyses and reports, is how to understand the Southwest Boundary Zone seismic source(s) and their contribution. This is because there remains uncertainty in the overall understanding of that contribution, and future investigations, both measurements in the field and through analysis and analogue studies, will be important in clarifying those uncertainties.

However, the PG&E participants in this Fact-Finding session seemed to broadly believe that however that future work emerges, it seems unlikely that the overall impact of the Southwest Boundary Zone sources on DCPP site hazard will be large. They had concluded that the hazard associated with the Hosgri Fault system is by far the largest contributor to overall plant risk, and that predominance is very unlikely to change significantly regardless of the results of the future Southwest Boundary Zone research.

**<u>Conclusions</u>: Three different meetings were held between PG&E, DCISC members and consultants, and the DCISC's Seismic Review Team on August 19, September 10, and September 17, 2025, to discuss the seismic hazard at the DCPP site and the Seismic Review Team's recommendations. Information gathered in the meetings will be used to inform the DCISC's decisions as to how to disposition those recommendations in upcoming public meetings and PG&E's future responses to the recommendations.**

**<u>Recommendation to the DCISC or PG&E</u>: None.**

### 3.11 <u>Meet with DCPP Director</u>

The DCISC FFT met with Tom Jones, Regulatory, Environmental and Repurposing Senior Director, for an update. The DCISC last met with a DCPP officer during its Fact-Finding Meeting in August 2025 (Reference 6.13) when it concluded the following:

*The introductory meeting of new DCISC Member Meshkati with Chief Nuclear Officer Paula Gerfen and Vice-President Maureen Zawalick was beneficial to both organizations for familiarization and professional interests.*

The participants discussed the current meeting agenda items and other items of mutual interest.

**Conclusions: The regular meetings with DCPP Officers and Directors continue to be beneficial for both organizations.**

**Recommendations to PG&E or DCISC: None.**

3.12 Emergency Diesel Generators

The DCISC FFT met with Mike LaChance, Emergency Diesel Generator (EDG) System Engineer for an update on EDG system performance, and DCISC Member Dr. Raluca Scarlat participated remotely. Delphine Hou, Harpreet Bhalla, Deb Luchsinger, and Jerry Bischof from the California Department of Water Resources (DWR) also participated remotely in the meeting. The DCISC last reviewed the health of EDGs in January 2024 (Reference 6.14), when it concluded the following:

*The DCPP Emergency Diesel Generators for both units are rated in Green Health (Healthy) with a few challenges in fuel oil day tank level instruments and panel alarm relay modules. Satisfactory plans for these challenges are underway.*

The EDGs are safety-related pieces of equipment whose functions are as follows:

- To furnish sufficient electric power to mitigate a design basis accident in one unit and safely bring the other unit to cold shutdown when both the 230kV and 500kV offsite power sources are unavailable.
- To act as a backup source of power to enable the reactor to continue to produce power for 72 hours whenever there is no accident condition, but one of the two offsite power sources is inoperable.
- To furnish power sufficient for an emergency shutdown of the plant during a loss of offsite power sources.

The EDG Fuel Oil Supply system has enough fuel capacity to provide seven days of onsite power generation: (a) in order to operate the minimum required Engineering Safety Features equipment following a design basis Loss-of–Coolant Accident for one unit, and the equipment in the second unit is in either the hot or cold shutdown condition, or (b) when the equipment for both units is in either the hot or cold shutdown condition. Each nuclear operating unit is supported by three EDGs dedicated to the respective unit, and the EDGs can be cross connected to the other unit using temporary cables. The EDGs are each rated to deliver approximately 2,600 kW on a continuous basis and are designed to start automatically when needed. Additional temporary power generators are provided as a part of the FLEX Program and can be used to power plant equipment should the EDGs not be available.

Mr. LaChance reviewed the health of the three Unit 1 and three Unit 2 EDGs with the FFT and provided copies of the associated System Health Reports. Both Units' EDGs were classified as Green (Healthy) overall with the following issues challenging system health and driving 2 of 26 sub-indicators into the White (Needing Improvement) category:

- Fuel oil day tank level switch design deficiencies result in repeat testing failures and challenges. An upgrade project has been approved, and the procurement of replacement switches is in progress.

- "GQD" panel alarm relay modules are obsolete with no spares in stock. An upgrade project for the alarm panels was approved and replacement systems have been received. Upgrade implementations began during the recent Maintenance Outage Window for EDG 2-2 in August 2025.

As discussed during previous DCISC reviews, the original EDG control system components (Woodward motor-operated potentiometer governors) became no longer available and considered obsolete. Modifications to upgrade the governors were previously completed on four of the six EDGs. With the proposal to extend power operations beyond 2025, the project to replace the two remaining governors was authorized and the FFT found that the replacements were completed in 2024. The FFT found that EDG reliability and unavailability numbers remained good and well within established goals. The last EDG start failure occurred on EDG 1-1 in September 2015.

Mr. LaChance briefed the FFT regarding recently completed major maintenance activities (referred to as Maintenance Outage Windows, or "MOWs", which described the means for managing the scheduling of EDG maintenance). During 2025, DCPP completed major maintenance activities on five of the six EDGs, with the sixth EDG having previously received major maintenance in late 2024. These major maintenance activities, which typically last for about 14 days, included extensive preventive maintenance on mechanical components as recommended by the vendor as well as reliability improvements consistent with ensuring EDG reliability remains high during a period of extended operations. Corrective maintenance activities were also scheduled for resolution during these maintenance periods.

The FFT was also briefed on two equipment problems that occurred during post-maintenance tests following the recent EDG maintenance activities. On July 22, 2025, following major maintenance activities on EDG 2-3, the EDG tripped on overspeed during a full-load rejection test (Notification 51294745). Investigations and troubleshooting identified that the tail of a cotter pin on the fuel rack linkage had struck a stop bolt thereby limiting the ability of the governor to respond to a speed excursion and allowing speed to increase to the overspeed trip setpoint. The problem was resolved by reinstalling the cotter pin in such a manner that it could not strike the stop bolt in the future, and the EDG was successfully retested and returned to service. Additional corrective actions to prevent recurrence were being tracked by the Corrective Action Program. Extent of condition reviews found that the problem could not occur on the other five EDGs because the stop bolts installed on the other five EDGs were procured earlier in plant construction than those for EDG 2-3 and were not of the design used for EDG 2-3 which was unique to that EDG.

On September 5, 2025, following maintenance activities on EDG 2-2, a jacket water leak occurred from the jacket water pump telltale drain (SAPN 51300035). The leak (about 0.3 gph) was active only during EDG operation and was indicative of minor seal degradation on the pump. The magnitude of the leak was reviewed and determined to be acceptable for continued operability provided that a compensatory measure was established to check jacket water tank level every two hours during EDG 2-2 operation and replenish the coolant if tank level fell below 12 inches (eight gallons). The telltale drain on EDG 2-2 was also being regularly checked daily during normal standby (non-running) conditions by operators performing their regular inspections.

The FFT requested further information on DCPP's evaluation of continued operability for EDG 2-2 with the jacket water pump seal leak. The notification above (SAPN 51300035) referred to another notification, SAPN 50838199, for the evaluation of continued operability. That notification was provided to the FFT following the meeting, and the FFT found that the two notifications appeared to conflict with regards to the EDG mission times used in the operability evaluations. Specifically, SAPN 51300035 stated that the EDG mission time was 7 days (as also discussed in the FFT's meeting with PG&E staff), but SAPN 50838199 stated that the EDG mission time was 24 hours with reference to a 1993 PG&E letter as the basis for the 24-hour mission time. SAPN 50838199 then appeared to use the shorter 24-hour figure as a part of the basis for determining EDG operability but contained other statements regarding a 7-day mission time. Given that much of this information was received by the FFT following the Fact-Finding meeting, there was not an opportunity for the FFT to further discuss these documents in detail with PG&E. Accordingly, the FFT recommends that the DCISC further review DCPP's mission times and their bases as used in the operability determination for a jacket water pump seal leak on EDG 2-2.

Dr. Scarlat inquired at what point the leak would be repaired, and Mr. LaChance reported that the leak was planned for repair during the next regularly scheduled MOW for EDG 2-2, but it would be repaired earlier if the leak grew worse (doubled). The repair work was estimated to require three shifts or about one and one-half days. Additional corrective actions to prevent recurrence were being tracked by the Corrective Action Program. The FFT concluded that both equipment failures were being satisfactorily addressed by DCPP.

**<u>Conclusions</u>: The health of DCPP's Emergency Diesel Generators for both units were rated as Green (Healthy) with no major equipment issues. Equipment challenges with fuel oil day tank level instruments and alarm panel relay modules were being satisfactorily addressed. Two equipment failures that recently occurred during post-maintenance tests were being effectively addressed via the Corrective Action Program, and the DCISC had additional questions regarding the mission time used in an operability evaluation for Emergency Diesel Generator 2-2.**

**<u>Recommendation for the DCISC</u>: The DCISC should further review DCPP's basis for developing mission times used in an operability determination for a jacket water pump seal leak on Emergency Diesel Generator 2-2. (D9/25FF-3.12)**

**<u>Recommendations to PG&E</u>: None.**

3.13 <u>Plant Tour</u>

The DCISC FFT met with Mike LaChance, Emergency Diesel Generator (EDG) System Engineer, for a tour of plant areas containing EDGs 2-2 and 2-3 which were the subjects of discussions in Section 3.12 above. Brandy Lopez, Nuclear Program Manager and DCISC Liaison, also accompanied the FFT on the tour. The DCISC last toured an area of the plant during its August 2025 Fact-Finding Meeting (Reference 6.15), when it toured the area containing EDG 2-3 and observed a test of the FLEX Diesel-Driven Raw Reservoir Pump and concluded the following:

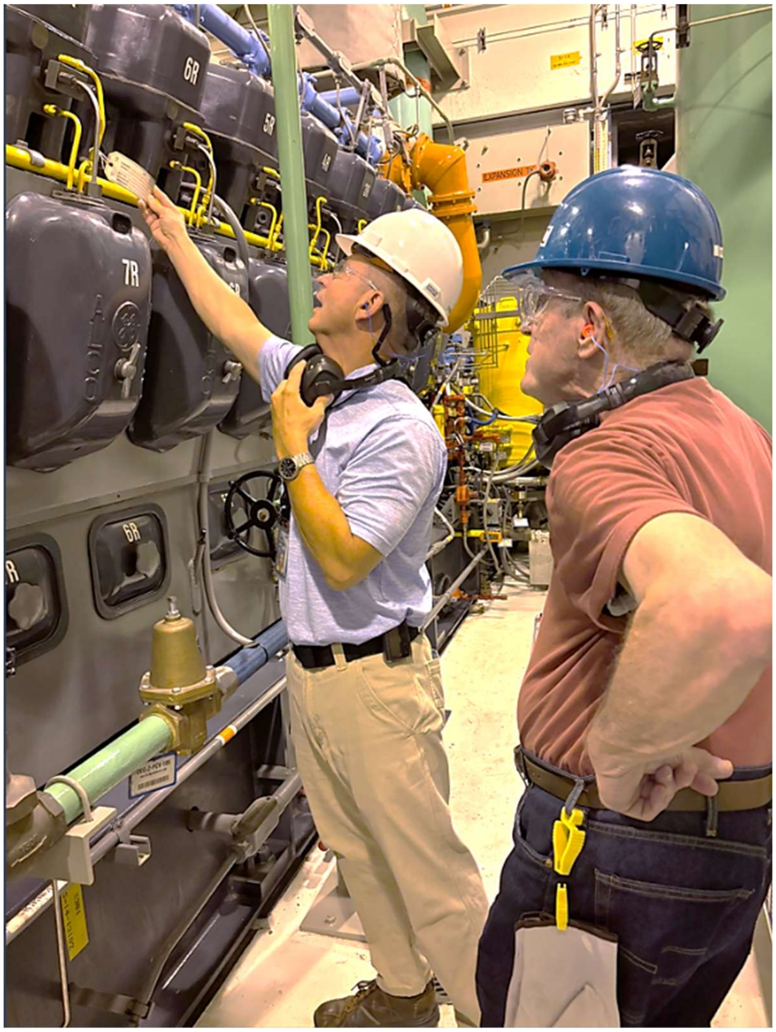
> *The DCISC FFT tour of Emergency Diesel Generator showed that the engine and its room were clean and orderly and the DCPP escort was knowledgeable about the machine and its systems.*
>
> *The quarterly FLEX Diesel-driven Raw Reservoir Pump Test was performed successfully.*

At the request of the FFT, Mr. LaChance and Ms. Lopez guided the team in touring several areas of the Unit 2 Turbine Building. Areas toured included:

- Unit 2 Turbine Deck (119' Elevation)
- Unit 2 Turbine Building (85' Elevation), Secondary Plant Support Systems
- Unit 2 Turbine Building (85' Elevation), Emergency Diesel Generator Rooms 2-2 and 2-3

Selected pictures of areas toured by the FFT were as follows:


Dr. Budnitz and Mr. McWhorter at Unit 2 Main Generator




Mr. LaChance and Dr. Budnitz at the 2-2 Emergency Diesel Generator

Overall, the FFT found that the areas toured were clean, orderly, and well lit, with equipment in good condition.

**<u>Conclusion</u>: A tour of two Unit 2 Emergency Diesel Generator Rooms found them to be clean and orderly with equipment in good condition.**

**<u>Recommendations to the DCISC or PG&E</u>: None.**

## 4.0 CONCLUSIONS

**4.1 DCPP satisfactorily completed its Mid-Cycle Self-Assessment which was performed as a part of programs overseen by the Institute of Nuclear Power Operations.**

**4.2 DCPP twice took action to reduce Unit 2 power levels to preclude the possibility of incurring an automatic unit trip initiated by the Special Protection System if multiple 500kV transmission lines were lost during local wildfire events. The DCISC found**

**that these proactive decisions, which were initiated by DCPP, were appropriate and reflected a conservative approach by station leadership in making major decisions.**

**4.3 DCPP's Single Point Vulnerability Program was being managed well under plant processes and procedures, and it is now considered a part of DCPP's broader programs to foster high Equipment Reliability.**

**4.4 DCPP provided responses to questions and concerns received by the DCISC from a member of the public regarding methods used to inspect Spent Fuel Multi-Purpose Canisters for corrosion. Additional information was requested during this Fact-Finding Meeting and later provided by PG&E. The DCISC should review this revised information during a future Fact-finding Meeting.**

**4.5 PG&E completed evaluations regarding why procedure changes made as a result of a 2018 Root Cause Evaluation for an Auxiliary Saltwater Pump motor bearing failure were not sufficiently effective to prevent the recurrence of a similar issue in 2023, and appropriate changes to the Corrective Action Program were initiated.**

**4.6 DCPP's preparations for Refueling Outage 2R25 appeared to be progressing satisfactorily.**

**4.7 The 230kV and 500kV Transmission Systems at DCPP were both in good health with no major issues. Projects are being implemented to upgrade breakers and relays in the DCPP switchyards.**

**4.8 A September 16, 2025, Readiness Review Board meeting was conducted efficiently and effectively. Representatives from various departments focused on ensuring that outage secondary system shutdown and startup activities were appropriately scheduled.**

**4.9 DCPP's update on recent station activities was informative, and no new major issues were identified.**

**4.10 Three different meetings were held between PG&E, DCISC members and consultants, and the DCISC's Seismic Review Team on August 19, September 10, and September 17, 2025, to discuss the seismic hazard at the DCPP site and the Seismic Review Team's recommendations. Information gathered in the meetings will be used to inform the DCISC's decisions as to how to disposition those recommendations in upcoming public meetings and PG&E's future responses to the recommendations.**

**4.11 The regular meetings with DCPP Officers and Directors continue to be beneficial for both organizations.**

**4.12 The health of DCPP's Emergency Diesel Generators for both units were rated as Green (Healthy) with no major equipment issues. Equipment challenges with fuel oil day tank level instruments and alarm panel relay modules were being satisfactorily**

**addressed. Two equipment failures that recently occurred during post-maintenance tests were being effectively addressed via the Corrective Action Program, and the DCISC had additional questions regarding the mission time used in an operability evaluation for Emergency Diesel Generator 2-2.**

**4.13 A tour of two Unit 2 Emergency Diesel Generator Rooms found them to be clean and orderly with equipment in good condition.**

## 5.0 RECOMMENDATIONS

**<u>Recommendations to the DCISC:</u>**

**5.1 The DCISC should follow up at a future Fact-Finding Meeting with additional review of PG&E's revised responses to questions and concerns regarding methods used to inspect Independent Spent Fuel Storage Facility Multi-Purpose Canisters for corrosion. (D9/25FF-3.4)**

**5.2 The DCISC should further review DCPP's basis for developing mission times used in an operability determination for a jacket water pump seal leak on Emergency Diesel Generator 2-2. (D9/25FF-3.12)**

**<u>Recommendations to PG&E:</u>**

**5.3 The following previous recommendation to PG&E was reviewed in this Fact-Finding Meeting (Section 3.5) and is recommended for closure: *PG&E should continue to evaluate why a 2018 Root Cause Evaluation for a failed Auxiliary Saltwater Pump motor bearing did not result in sufficiently effective procedure changes (P11/24FF-3.11)*.**

## 6.0 REFERENCES

6.1 "Diablo Canyon Independent Safety Committee Thirty-Fifth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2024 – June 30, 2025," Scheduled for approval at the October 23, 2025, DCISC Public Meeting, Volume II, Exhibit D.4, Section 3.10, "World Association of Nuclear Operators Peer Review Results."

6.2 "Diablo Canyon Independent Safety Committee Thirtieth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2019 – June 30, 2020", Approved October 29, 2020, Volume II, Exhibit D.7, Section 3.8, "Special Protection System."

6.3 "Diablo Canyon Independent Safety Committee Thirty-Sixth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2025 – June 30, 2026," Scheduled for approval at the October 21, 2026, DCISC Public Meeting, Volume II, Exhibit D.2, Section 3.10, "Single Point Vulnerability Update."

6.4 Ibid., Exhibit D.1, Section 3.11, "Independent Spent Fuel Storage Installation (ISFSI) Update."

6.5 Pacific Gas and Electric Company, "License Renewal Application for the Diablo Canyon Independent Spent Fuel Storage Installation," Submitted to the US Nuclear Regulatory Commission as PG&E letter DIL-22-003, March 9, 2022, Available in NRC Agencywide Documents Access and Management System (ADAMS) under ML22068A189.

6.6 "Diablo Canyon Independent Safety Committee Thirty-Fifth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2024 – June 30, 2025," Scheduled for approval at the October 23, 2025, DCISC Public Meeting, Volume II, Exhibit D.9, Section 3.5, "Root Cause Evaluation for Auxiliary Saltwater Pump Motor Failure."

6.7 Ibid., Exhibit D.7, Section 3.10, "Refueling Outage 1R25 Update and Safety Plan.

6.8 Diablo Canyon Independent Safety Committee Thirty-Third Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2022 – June 30, 2023," Approved September 13, 2023, Volume II, Exhibit D.6, Section 3.12, "Transmission System Health Update."

6.9 "Diablo Canyon Independent Safety Committee Thirty-Fifth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2024 – June 30, 2025," Scheduled for approval at the October 23, 2025, DCISC Public Meeting, Volume II, Exhibit D.10, Section 3.9, "Observe Outage Scope Review Team and Daily Notification Review Team Meeting."

6.10 "Diablo Canyon Independent Safety Committee Thirty-Sixth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2025 – June 30, 2026," Scheduled for approval at the October 21, 2026, DCISC Public Meeting, Volume II, Exhibit D.1, Section 3.10, "Plant Update."

6.11 "Diablo Canyon Independent Safety Committee Thirty-Fifth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2024 – June 30, 2025," Scheduled for approval at the October 23, 2025, DCISC Public Meeting, Volume II, Exhibit D.9, Section 3.2, "High-Pressure Turbine Replacement Update and Plant Tour."

6.12 "Review of the Bird Critique by the Seismic Review Team of the Diablo Canyon Independent Safety Committee," May 30, 2025, by Drs. Thomas Jordan, Michael Oskin, and Scott Marshall, Endorsed at the June 11, 2025, DCISC Public Meeting. Included in "Diablo Canyon Independent Safety Committee Thirty-Fifth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2024 – June 30, 2025," Scheduled for approval at the October 23, 2025, DCISC Public Meeting, Volume II, Exhibit D.12, "Review of the Bird Critique."

6.13 "Diablo Canyon Independent Safety Committee Thirty-Sixth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2025 – June 30, 2026," Scheduled for approval at the October 21, 2026, DCISC Public Meeting, Volume II, Exhibit D.2, Section 3.2, "Meeting with DCPP Officers Paula Gerfen and Maureen Zawalick."

6.14 "Diablo Canyon Independent Safety Committee Thirty-Fourth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2023 – June 30, 2024," Approved October 10, 2024, Volume II, Exhibit D.6, Section 3.12, "Emergency Diesel Generator Update."

6.15 "Diablo Canyon Independent Safety Committee Thirty-Sixth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2025 – June 30, 2026," Scheduled for approval at the October 21, 2026, DCISC Public Meeting, Volume II, Exhibit D.2, Section 3.11, "Emergency Diesel Generator Walkdown" and Section 3.13, "Observe Quarterly FLEX Diesel-Driven Emergency Saltwater Pump Flow Test."

DCISC Questions (Received from a Member of the Public) Regarding Multipurpose Canister Corrosion and Answers Provided by PG&E on October 7, 2025

1. "Does PG&E have results of a Repeatability and Reproducibility study utilizing defects representative of stress corrosion cracking for the tool that provided the depth measurements of 0.008 inches and 0.014 inches that are referenced in the Evaluation of MPC [Multi-Purpose Canister] Discoloration, Staining in Section E.6.1.1 of the license renewal application (LRA)?"

   PG&E Response:

   "Measurement and Test Equipment used to perform both visual inspections and characterization measurements of the canisters is calibrated by the equipment supplier to NIST (National Institute of Standards and Technology) standards as part of the manufacturing process. The inspection probe capabilities are then verified through demonstration prior to the inspection, at intervals during performance of the inspection and following completion of the inspection. The verification of continued calibration for the instrument probes is typically performed using a verification block that is provided by the supplier of the instrument probe. The verification block contains known manufactured indications at different lengths and depths that are used to compare instrument readings against the known values to verify calibration of the instrument probe prior to, during, and after performing the inspections. The verification blocks are also supplied to NIST standards and are serialized for traceability."

2. "Will the same tool be used in the next inspection (anticipated to occur in 2026)? If so, will R&R (or any demonstration effort) results be obtained prior to use?"

   PG&E Response:

   "Yes, PG&E will use the same inspection services and processes for the 2026 inspection. However, PG&E plans to use an updated model of the MViQ bore scope system. This newer model is one of the most advanced bore scopes available and provides greater precision and accuracy than the MViQ system that was used for the inspections that were performed in 2021.

   Calibration verification of the instrument will be performed as noted in the response to the prior question, and similar to the 2021 inspections."

3. "Section E.6.1.1 states '*there is no observed degradation on the MPC shells from the discoloration or staining; therefore, there is no impact on the MPC shell base material.'* - Considering that visual examination methods have not been shown capable of observing stress corrosion cracking and considering that the presence of rust deposits is obscuring the surface of the MPC shells, how is this conclusion supported?"

   PG&E Response:

   "NUREG-2214, "Managing Aging Processes in Storage," provides guidance that propagation rates for pitting measured under marine environments would require more than 250 years to penetrate an MPC shell, and that propagation rates for crevice corrosion would require more than 400 years to penetrate an MPC shell.

Based on the identified rust indications on the examined MPCs being 0.008 inches or less in depth (which equates to approximately 1.8 percent of the minimum MPC shell thickness), PG&E's engineering assessment concluded that the rust indications are representative of pitting and crevice corrosion, and therefore the corrosion propagation rates for the examined MPCs are bounded by the propagation rates specified in NUREG-2214. Therefore, the function of the MPC shell base material is maintained, and the inspection interval of 5 years is appropriate for continued monitoring of the MPCs in accordance with the NRC approved aging management program."

4. "Section E.6.1.1 also states – '*Further, NUREG-2214, Table 6-2, Element 10, cites research findings that yield a SCC growth rate of 0.06 inches in a 5-year period (see Figure 5 for MPC minimum wall thickness). Therefore, the next inspection interval of 5 years as proposed in the MPC AMP is acceptable.'* Figure 5 shows a total thickness of 0.5 inches and a minimum thickness of 0.45 inches, considering that 0.5 - 0.06 is 0.44 (and the remainder would be further reduced by the unknown starting pit/crack depth), how is the 5-year interval acceptable?"

   PG&E Response:

   "Figure 5 was cited when discussing Stress Corrosion Cracking (SCC) to aid in public understanding of the MPC design and was not meant to imply the 0.45" minimum wall thickness was a limit for SCC – rather, through-wall is the limit for SCC. The inspections conducted in 2021 confirmed there are no cracks on the MPC external surfaces, only surface rust (up to 0.008" deep). Therefore, potential growth of 0.06" of a non-existent crack could take the wall thickness to 0.44". This is not through-wall, and thus, the MPC would maintain its intended function. Since there was no evidence of cracks identified in 2021, the inspection interval of 5 years remains adequate."

5. "The SCC growth rate cited above is based on natural exposure tests, SCC growth rates are highly temperature dependent and canister surface temperatures are significantly elevated compared to atmospheric temperatures, this crack growth rate is likely non-conservative. How is crack growth rate uncertainty being considered in the inspection interval?"

   PG&E Response:

   "Crack growth rates are accepted by the industry, EPRI [Electric Power Research Institute], and NEI [Nuclear Energy Institute] as extremely slow. The 5-year inspection interval is the most frequent required by the NRC. In order for CISCC [Chloride-Induced Stress Corrosion Cracking] to possibly occur, all three conditions must exist; a susceptible material, a sustained stress, and a wetted contaminate. The high temperatures and dry conditions inside the overpack do not allow the canister surface to experience such moisture, and therefore, lower the susceptibility for chloride induced cracking to occur. Therefore, the industry referenced growth rate is an appropriately conservative rate.

   To provide further confidence there is no CISCC occurring at the DCPP ISFSI that could challenge the 5-year inspection interval, PG&E conservatively inspected 8 MPCs during the voluntary pre-application inspection versus the industry standard of 1-2 MPCs."

6. "I would ask what their response was to the info notice 2012-20. (Examples were in 304 and 304L pipes - not canisters - different stress conditions)"

   PG&E Response:

   "The intent of the Information Notice was to bring attention to ISFSI license holders that their systems are susceptible to CISSC. PG&E understands that CISCC is a credible aging mechanism and addresses it throughout their MPC Aging Management Program. Additionally, PG&E transitioned to 316/316L canister material for enhanced corrosion resistance, particularly in chloride environments."

7. "How confident they are about the depth of the "rust" found? How measured or evaluated?"

   PG&E Response:

   "The verification measurements (as previously described) in the report were determined to be accurate. Therefore, the measurements would be accurate +/-.0002 inches (per the OEM)."

8. "Have they found any evidence of CISSC on the canisters (the assumption is that it is occurring under the 'rust')?"

   PG&E Response:

   "No evidence of chloride induced stress corrosion cracking has been observed in any in-service canisters in the industry."

9. "Are there any NDE [Non-Destructive Examination] tools or UT [Ultrasonic Testing] that can get into the area in question - have they been qualified?"

   PG&E Response:

   "In coordination with EPRI, PG&E's inspection vendor is actively performing development and testing activities to qualify an eddy current inspection system that will support further investigation of potential indications in the welds and heat affected zones of in-service fuel storage canisters. The goal of the effort is to develop an eddy current system that can be deployed in multiple designs and configurations of fuel storage canisters with a successfully demonstrated ability to provide objective, accurate, and repeatable results.

   EPRI has yet to publish a report documenting the results of the system demonstration and testing, but PG&E remains engaged in the latest research and development efforts related to canister inspections and will evaluate the use of eddy current testing during the 2026 inspections."

10. "Is the instrument capable of seeing through the rust or does it have to be removed first?"

    PG&E Response:

    "This specific bore scope is not capable of 'seeing' through rust or debris. A caveat to that is if the indication is severe enough to affect the landscape immediately surrounding the indication, you will still be able to 'see' the indication telegraph on the surface of the rust or debris covering it. The area of severe corrosion would need to be cleaned to see the full dimensions and impact of the indication."

11. "Has there been any industry experience with rust on canisters or experimental work showing that it may passivate the SCC or increase the CISCC?"

    PG&E Response:

    "Through PG&E's active participation in EPRI's Extended Storage Collaboration Program, as well as multiple dry fuel storage Users Groups, where OE [Operating Experience] on this topic is continuously shared and discussed, stress corrosion cracking has never been observed on any in-service dry fuel storage canisters, nor has there been positive confirmation that canisters are displaying passivation as a result of rust."

Report by Michael Oskin to the DCISC Seismic Review Team

September 23, 2025

Dr. Michael Oskin
Professor of Geology
University of California, Davis

To: Diablo Canyon Independent Safety Committee and Seismic Review Team

Re: Report from Southern Santa Maria Basin Field Trip, August 19, 2025

This is a report of findings the 19 August 2025 field trip to active faults and related geological features of the southern Santa Maria Basin. The trip was co-led by Dr. Nathan Onderdonk, Professor Geology, California State University Long Beach, and Ian McGregor, a former Masters student of Dr. Onderdonk and presently employed by Lettis Consultants International (LCI). Additional participants on this trip include PG&E staff geoscientists (Chris Madugo, Jeff Bachhuber, Luther Strickland), members of the IPRP (Gordon Seitz, Time Dawson, Philip Johnson), a member of the U.S. Geological Survey (Charles Trexler) and LCI employees and consultants (Jeff Unruh, Tom Rockwell, Jeff Blozies, Steve Thompson). The primary objective of this trip was to view evidence for uplift, folding, and river incision into the Orcutt Formation, a widespread sedimentary deposit mantling this region. It is from deformation of the Orcutt Formation that McGregor and Onderdonk (2021) deduced a high, 5.6-6.7 mm/yr rate of slip for the Casmalia Hills thrust, located approximately 35 km southeast of Diablo Canyon. For comparison, this rate of slip is at least twice the rate of the Hosgri fault.

Summary of Field Trip Stops:

The first stop of the trip visited an outcrop of the Lions Head fault where it intercepts the coastline near Point Sal. This site is located on the Vandenberg Space Force Base. The fault cuts a marine terrace associated with the stage 5e sea-level highstand at 124.0 +/- 2.5 thousand years ago. The Lions Head fault strikes parallel to and is situated within the hangingwall of the Casmalia Hill thrust. This fault configuration is similar to the position of the Los Osos trend with respect to the Southwest Boundary Zone fault system underlying the Irish Hills. From sea cliff exposures, we observed that strands of the Lions Head fault dip steeply, from 50 degrees to near vertical. This fault zone exhibits evidence of both strike-slip and reverse motion. The rate of fault slip here is not yet fully documented, but only a few meters of uplift of the marine terrace is observed where the fault cuts its base, suggesting a vertical slip rate below 0.1 mm/yr.

The second stop of the trip was an overview of the Orcutt formation where it forms an extensive topographic terrace (Vandenberg Mesa) near the mouth of the Santa Ynez River. At this site there was extensive discussion of the age of the Orcutt formation, which McGregeor and Onderdonk (2021) and Kelly and Onderdonk (2022) argue to be between 119 +/- 11 and 85 +/- 6 thousand years, comparable to the age of the Q1 and Q2 marine terraces fringing the Irish Hills. Dr. Rockwell and I disputed the validity of this age of the Orcutt formation due to the eroded and diffused edges of the Vandenberg terrace, suggesting greater antiquity, and due to the mismatch between the terrace elevation and the considerably lower elevation of Q1- and Q2-equivalent marine terraces along the coast between the Point Conception and Point Sal.

The third and fourth field trip stops viewed the Orcutt formation where it forms an elevated terrace south above the Santa Ynez River near Buellton. The field trip participants noted the presence of quartz-bearing sediment within the Orcutt formation and discussed how exposure dating techniques could be applied to validate its age. We also reviewed evidence from Kelly and Onderdonk (2022) for the uplift rate above the Santa Ynez River fault. The rate of slip on this fault also critically depends on the age of the Orcutt formation.

The final field trip stop viewed evidence for left slip on the Santa Ynez fault east of Lake Cachuma. Here we also viewed new results from in-progress effort by McGregor and Onderdonk to construct cross-sections of the southern Santa Maria thrust belt east of the presently published work at the Casmalia Hills. These in-progress cross-sections showed reverse-fault reactivation of a former rift basin margin, notably similar to the configuration of faulting present beneath the Irish Hills. We discussed evidence for the dip angle of faulting beneath the Casmalia Hills and how this compared with fault dips inferred from these new, yet unpublished cross-sections. McGregor noted that the Casmalia Hills thrust dip was controlled by an oil-well intercept.

Findings Regarding Slip-Rate of the Casmalia Hills thrust:

The high rate of slip on the Casmalia Hills thrust argued by McGregor and Onderdonk (2021) depends foremost on the age of the Orcutt formation. Though the Casmalia Hills thrust does not reach the surface, evidence for its activity is preserved in folding and uplift of the Orcutt formation over the crest of the hills, reaching a maximum of 283 meters relative to correlative outcrops within the Santa Maria basin. Using the 85-119 kyr age for the Orcutt formation, this yields an uplift rate of 2.4-3.3 mm/yr. The dip of the Casmalia Hills fault also affects the interpreted slip rate; a lower dip increases the rate of slip needed to accomplish the observed uplift rate. The dip of the Casmalia Hills fault is constrained to be approximately 30 degrees based on projection of a fault intersection within one oil well to a zone of intense folding associated with up-dip fault propagation. This fault configuration, originally proposed by Namson and Davis (1990), is modestly updated by the later work by McGregor and Onderdonk (2021). In my personal view, alternative solutions with a slightly steeper fault dip may be permitted, but a dip greater than about 40 degrees would not honor the available subsurface data. The 30 degree inclination of bedding within the fault hangingwall further constrains the fault to dip to be 30 degrees or greater, as a lower fault dip value would result in an unusual downward cutoff angle between bedding and the fault plane.

Based on the observed characteristics of eroded outcrops of Orcutt Formation, and mismatch in elevation of Vandenberg Mesa with age-equivalent marine terraces, it is likely that the age of the Orcutt formation has been underestimated by the currently employed luminescence technique. During the field trip the participants discussed ideas to validate this age through exposure-age dating. A three- to four-meter-deep excavation of an unmodified area of Vandenberg Mesa would provide access to samples needed to construct a cosmogenic 10Be exposure depth profile and independently date the Orcutt formation.

Comparison to reverse faulting beneath the Irish Hills:

Both the Irish Hills and Casmalia Hills lie within the Santa Maria basin and are formed by slip on reverse faults. It is thus useful to compare the geological features of these two systems in order to better understand the characteristics and uncertainty of faulting. Both ranges exhibit tilting of strata in the fault hangingwall due to a change in reverse fault dip at depth. The dip of the upper part of the fault is a key piece of information needed to model the fault geometry at depth. For the case of the Irish Hills, the mean dip of 38 +/- 3 degrees is constrained from outcrop data. For the case of the Casmalia Hills, where the fault does not reach the surface, fold geometry and oil-well data constrain fault dip to be 30 degrees, with slightly higher values permitted. The total fault slip since 5 million years ago is somewhat higher for the Casmalia Hills, at 3.1-4.2 km (McGregor and Onderdonk, 2021) versus 2.6 +/- 0.3 km for the Irish Hills. The key difference between the ranges is the average fault slip rate from approximately 120 thousand years ago to present. Marine terrace uplift yields a slip rate of 0.29 +/- 0.07 mm/yr for the Irish Hills. This rate is comparable to the long-term rate since 5 million years ago. Folding of the Orcutt formation yields a slip rate of 5.6 to 6.7 mm/yr. This rate is an order of magnitude faster than the long-term rate. However, considering the concerns raised for the luminescence ages of the Orcutt formation, the high rate of slip for the Casmalia Hills should be validated with additional age information.

Sincerely,

Michael Oskin

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*Namson, Jay, and Thom Davis. "Late Cenozoic Fold and Thrust Belt of the Southern Coast Ranges and Santa Maria Basin, California (1)." Bulletin of the American Association of Petroleum Geologists 74 (1990).*