Application: 18-12-
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Date: December 13, 2018
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2018 NUCLEAR DECOMMISSIONING COST TRIENNIAL PROCEEDING

PREPARED TESTIMONY

VOLUME 1

PACIFIC GAS AND ELECTRIC COMPANY
2018 NUCLEAR DECOMMISSIONING COST TRIENNIAL PROCEEDING
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TABLE OF ACRONYMS

Abbreviation	Full Name or Context
A.	Application
10 CFR	Title 10 of the Code of Federal Regulations
40 CFR	Title 40 of the Code of Federal Regulations
A&G	Administrative and General
A4NR	Alliance for Nuclear Responsibility
AB	Assembly Bill
ACI	Advanced Concepts Incorporated
ACRS	Advisory Committee of Reactor Safeguards
AEA	Atomic Energy Act
AET	Annual Electric True-Up
AFUDC	Allowance for Funds used During Construction
AL	Advice Letter
ALARA	Due to As Low As Reasonably Achievable
ALARA	As Low As Reasonably Achievable
AMP	Aging Management Programs
ARB	California Air Resources Board
ASLB	Atomic Safety Licensing Board
ASO	Armed Security Officers
BGS	Below Ground Surface
BMP	Best Management Practices
BOP	Balance of Plant
C&D	Cold and Dark
C&S	Codes and Standards
CAISO	California Independent System Operator

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Abbreviation	Full Name or Context
CAM	Cost Allocation Methodology
CAM Group	Cost Allocation Mechanism Group
CCA	Community Choice Aggregation
CCC	California Coastal Commission
CCCA	Coastal Consistency Certification Application
CDFW	California Department of Fish and Wildlife
CDP	Coastal Development Permits
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFH	certified fuel handler
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
CLB	Current Licensing Basis
COB	Center of Business
COC	Cost of Capital
CPUC or Commission	California Public Utilities Commission
CSLC	California State Lands Commission
CSM	Cutter-Soil Mix
CTF	cask transfer facility
CWC	Civil Works Contractor
CWIP	Construction Work in Progress
CWP	Civil Work Phase
CZMA	Coastal Zone Management Act
D.	Decision

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
DA	Direct Access
DBT	Design Basis Threat
DCCDBA	Diablo Canyon Capital Depreciation Balancing Account
DCDEP	Diablo Canyon Decommissioning Engagement Panel
DCE	Decommissioning Cost Estimate
DCGL	Derived Concentration Guideline Level
DCGL	Derived Concentration Guideline Levels
DCPP or Diablo Canyon	Diablo Canyon Power Plant
DCRBA	Diablo Canyon Retirement Balancing Account
DG	Distributed Generation
DHS	Department of Health Services
DOE	Department of Energy
DOR	Designer of Record
DR	Demand Response
DSAR	Defueled Safety Analysis Report
DTSC	Department of Toxic Substances Control
E3	Energy and Environmental Economics, Inc.
ECI	Employment Cost Index
EE	Energy Efficiency
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EM&V	Evaluation, Measurement, and Verification
ENR	Engineering News Record

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
EO	Executive Order
EOB	Executive Oversight Board
EP	Emergency Plan
EPC	Engineering, Procurement and Construction
EPC	Engineering, Procure and Construct
EPRI	Electric Power Research Institute
ER	Environmental Report
ERRA	Energy Resource Recovery Account
ESA	Energy Savings Assistance program
ESPI	Efficiency Savings and Performance Incentive
FF&U	Franchise Fees and Uncollectibles
FIT	Feed-in Tariff
FOAK	First of a Kind
FOE	Friends of the Earth
FSAR	Final Safety Analysis Report
FSR	Final Site Restoration
FSS	Final Status Survey
FSS	Final Site Survey
FTE	Full-Time Equivalent
GARDIAN	Gamma Radiation Detection and In-Container Analysis
GDP	Gross Domestic Product
GEIS	Generic Environmental Impact Statement
GHG	Greenhouse Gas
gpm	gallons per minute

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Abbreviation	Full Name or Context
GRC	General Rate Case
GTCC	Greater-Than-Class-C
GWd/MTU	gigawatt-days per metric ton of uranium
GWh	Gigawatt-hours
GWTS	Groundwater Treatment System
HBGS	Humboldt Bay Generating Station
HBPP	Humboldt Bay Power Plant or Humboldt PP
HLRWV	High-Level Radwaste Vault
HSA	Historical Site Assessment
IBEW	International Brotherhood of Electrical Workers
IE	Independent Evaluator
IMs	Intermodals
INPO	Institute of Nuclear Power Operations
IOU	Investor Owned Utility
IP	Industrial Packaging
IRC	Internal Revenue Code
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
ITC	Investment Tax Credit
Joint Parties	Parties to the Joint Proposal
Joint Proposal	Agreement re DCPP
KKNPP	Kashiwazaki-Kariwa Nuclear Power Plant
kV	kilovolt
kWh	Kilowatt-hours

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
LAR	License Amendment Request
LARW	Low-Activity Radioactive Waste
LCOE	Levelized Cost of Energy
LLRW	low-level radioactive waste
LLRWB	Low-Level Radwaste Building
LMLCC	Luigi Marré Land & Cattle Co.
LOB	Line of Business
LR	License Renewal
LRA	License Renewal Application
LRW	Liquid Radwaste
LRWB	Liquid Radwaste Building
LSE	Load Serving Entity
LTP	License Termination Plan
M&A	Mergers and Acquisitions
M&S	Materials and Supplies
MARSAME	Multi-Agency Radiation Survey and Assessment of Materials and Equipment Manual
MARSSIM	Multi-Agency Radiation Survey and Site Investigation Manual
MLLW	Mean Lower Low Water
MMth	Millions of The
MPC	Mutli-Purpose Canister
MPEF	Main Plant Exhaust Fan
MW	Megawatt
MWh	Megawatt-hours

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
NBC	Non-Bypassable Charge
NCRWQCB	North Coast Regional Water Quality Control Board
ND	Nuclear Decommissioning
ND NBC	Nuclear Decommissioning Non-Bypassable Charge
NDAM	Nuclear Decommissioning Adjustment Mechanism
NDCTP	Nuclear Decommissioning Cost Triennial Proceeding
NDT	Nuclear Decommissioning Trust
NEI	Nuclear Energy Institute
NEM	Net Energy Metering
NEPA	National Environmental Policy Act
NRC	Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council
NSGBA	New System Generation Balancing Account
O&M	Operations and Maintenance
OAD	Open Air Demolition
OAD	Open Air Demo
ODCM	Offsite Dose Calculation Manual
OP	Ordering Paragraph
ORAU	Oak Ridge Associated Universities
OSHA	Occupational Safety and Health Administration
OTC	Once Through Cooling
PAC	Program Administrator Cost
PCB	polychlorinated biphenyls

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
PCIA	Power Charge Indifference Adjustment
PDTS	Permanently Defueled Technical Specifications
PEEBA	Procurement Energy Efficiency Balancing Account
PEERAM	Procurement Energy Efficiency Revenue Adjustment Mechanism
PG&E	Pacific Gas and Electric Company
PMP	Project Management Plans
PPA	Power Purchase Agreement
PPE	Personal Protective Equipment
PPI	producer price index
PPP	Public Purpose Program
PRG	Procurement Review Group
PRM	Planning Reserve Margin
PSDAR	Post-Shutdown Decommissioning Activities Report
psi	per square inch
PTS	Pre-Treatment System
Pub. Util. Code	Public Utilities Code
PV	Photovoltaic
PWR	pressurized water reactor
QA	Quality Assurance
QC	Quality Control
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
RAI	Requests for Additional Information
RAM	Renewable Auction Mechanism
RCA	Radiological Control Area
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
REMP	Radiological Environmental Monitoring Program
RFB	Restricted Area Preparations; Refueling Building
RFO	Request for Offers
RFP	Request for Proposal
RMS	Records Management System
RP	Radiation Protection
RPS	Renewable Portfolio Standard
RPV	Reactor Pressure Vessel
SAFSTOR	Safe Storage
SAMA	Severe Accident Mitigation Alternatives
SAS	Security Alarm Station
SB	Senate Bill
SEIS	Supplemental Environmental Impact Statement
SER	Safety Evaluation Report
SF	Safety Factor
SFP	Spent Fuel Pool
SFPI	Spent Fuel Pool Island
SIA	Structural Integrity Associates
SLO	San Luis Obispo

TABLE OF ACRONYMS

Abbreviation	Full Name or Context
SLOBP	San Luis Obispo Bay Properties, Inc.
SME	Subject Matter Expert
SMF	Soil Management Facility
SNF	Spent Nuclear Fuel
SOE	Support of Excavation
SONGS	San Onofre Nuclear Generating Station
SRA	Schedule of Ruling Amounts
SRWB	Solid Radwaste Building
SSC	Systems, Structures, and Components
STARS	Strategic Teaming and Resource Sharing
STS	Special Tactical Services
SWPPP	Stormwater Pollution Prevention Plan
TLAA	Time Limited Aging Analysis
TS	Technical Specifications
U.S.	United States
UGBA	Utility Generation Balancing Account
VBS	Vehicle Barrier System
WAC	Waste Acceptance Criteria
WTW	Willis Towers Watson
WWF	Welded Wire Fabric

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

INTRODUCTION AND POLICY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
INTRODUCTION AND POLICY

A. Introduction

The purpose of this Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) is to review Pacific Gas and Electric Company's (PG&E) updated nuclear decommissioning cost estimates and determine the necessary customer contributions to fully fund the nuclear decommissioning trusts to the level needed to decommission PG&E's nuclear plants.

This application presents and supports the first detailed, site-specific decommissioning cost estimate (DCE) for Diablo Canyon Power Plant (DCPP or Diablo Canyon) Unit 1 and Unit 2 submitted by PG&E for California Public Utilities Commission (CPUC or Commission) review and approval after Commission approval of PG&E's decision to retire DCPP upon expiration of the current operating licenses.

This application also presents for Commission review and approval the DCE for remaining decommissioning activities at Humboldt Bay Power Plant (HBPP) and the costs incurred for HBPP decommissioning work completed since the previous NDCTP application. The successful HBPP decommissioning project is entering its final phase.

1. The 2018 DCE for DCPP Presents the Costs of an Executable Decommissioning Plan

In its decision approving retirement of DCPP at the end of the current operating licenses, the Commission set forth its expectation that PG&E would file a detailed, site-specific DCE for DCPP in the 2018 NDCTP.[1] As previously recognized by the Commission, in prior NDCTPs PG&E presented decommissioning cost studies based on industry-wide assumptions intended only to provide an estimate for financial planning purposes:

> The decommissioning cost estimates are not meant to be the final decommissioning plans and are developed as a sort of snapshot for the

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[1] Decision (D.) 18-01-022.

> first step in determining ratepayer-funded utility contributions. We expect them to use unit cost factors and to be a high level estimate….[2]

This DCE represents a fundamentally different cost estimate from the cost studies previously presented to the Commission. It was developed from the ground-up, without reference to the unit cost factor methodology used in prior cost studies. It relies on cost-based and historical bid-based estimating, direct experience from 10 years of full-scale decommissioning at HBPP, industry expertise, and benchmarking. It is a site-specific DCE developed based on a realistic schedule and it provides a more accurate picture of the actual expected cost of decommissioning than previous cost studies.[3] This DCE identifies the cost and schedule to complete: radiological decommissioning; termination of the Part 50 licenses; spent fuel management until Spent Nuclear Fuel (SNF) and Greater-Than-Class-C (GTCC) waste are transferred to an off-site storage facility; termination of the Diablo Canyon Independent Spent Fuel Storage Installation (ISFSI) license; and site restoration activities.

The total DCE is $4.8 billion (2017$). This estimate assumes an immediate transition to decommissioning status upon plant shut down. To support this prompt transition to physical decommissioning, the DCE includes $187.8 million (2017$) of decommissioning planning activities costs to be performed before plant shut down in 2024 and 2025. As explained in Chapter 3, performing these activities over the next six years, rather than waiting to initiate planning activities until after plant shut down, reduces the overall cost of decommissioning significantly. Due to restrictions on access to the DCPP Nuclear Decommissioning Trust (NDT or ND Trust), PG&E's request in this application is to recover the pre-shutdown decommissioning planning costs from customers directly in retail rates through the Nuclear Decommissioning Non-Bypassable Charge. PG&E proposes to recover the remaining costs from customers through contributions to the NDT. PG&E presents these ratemaking proposals in Chapter 11.

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2 D.14-12-082 at 98.

3 While this DCE represents an actual decommissioning plan, and will remain relevant for comparison purposes, it can be expected that as decommissioning approaches, PG&E will make modifications and improvements, and this DCE does not represent a commitment to perform decommissioning work exactly as presented in the DCE.

2. Drivers of Increase Over 2015 Decommissioning Cost Estimate

The overall activities required to decommission a dual unit pressurized water nuclear reactor have not changed since PG&E submitted its 2015 NDCTP application. As noted above, the significant difference between the DCE presented in this application and cost study presented the 2015 NDCTP application is that the DCE does not rely on unit cost factors, but instead estimates the cost to decommission DCPP based on vendor bids, industry experience, and benchmarking. The $4.8 billion DCE presented in this proceeding is $720 million higher than that presented in the 2015 NDCTP. The primary drivers of that increase are:

- <u>Waste/transportation/material management</u>: Waste disposal costs are the largest contributor to the increase. These have more than doubled as a result of an increase in both volumes and waste disposal rates, based on more accurate volume analysis and more defendable waste rates. The 2015 NDCTP did not, for example, delineate low activity radioactive waste which is estimated to be 5 million cubic feet of waste.
- <u>Program Management, Oversight, and Fees</u>: Water management costs, the costs to run the desalinization facility under contract with GE and later trucking in water after removal of the desalination plant, are notably higher. Staffing costs are higher due to more accurate analysis and an overall extended schedule. Emergency planning costs were updated to reflect commitments made to extend certain activities until license termination. Costs for permitting and fees have doubled, as have property taxes. Consumables (including Radiation Protection calibration and RP consumables such as clothing, etc.) costs are significantly higher based on more accurate forecasting and experience from HBPP.
- <u>Site Infrastructure</u>: For this DCE, detailed planning based on an executable schedule identified site infrastructure needs that weren't included in prior estimates. These include construction of waste handling facilities, construction of an Independent Spent Fuel Storage Installation (ISFSI) security building, upgrades to the rail yard in Pismo beach, and other modifications.

3. High Bridge Associates Review of DCE

Not only did PG&E rely on external expertise to develop the DCE, once developed, PG&E subjected the DCE to additional scrutiny by an independent third party. PG&E identified High Bridge Associates (HBA), with its nuclear-specific project management expertise, as an excellent resource to perform an independent review of the DCE.[4] PG&E asked HBA to review the overall decommissioning project execution schedule, which formed the basis of the DCE, as well as: security, waste disposal, reactor pressure vessel (RPV) and internals segmentation schedule, building demolition plan, system and area closure plan, PG&E oversight structure, and contingency. This independent review largely confirmed and supported the assumptions and costs in the DCE. Where assumptions and costs were challenged, PG&E responded, either by adjusting its assumptions or by committing to further evaluate the issue. After PG&E performs the recommended evaluations, PG&E will update the DCE and file supplemental testimony as necessary. Table 1-1 presents the major HBA findings and PG&E's response.

TABLE 1-1
HIGH BRIDGE ASSOCIATES STRENGTHS/FINDINGS AND PG&E RESPONSE

Subject Area	Findings	PG&E Response
Security	• Security staffing estimates are reasonable. • Due diligence in effort to determine and confirm security staffing levels exceeded expectations. • Reduction in spent fuel pool cooling duration will allow earlier security staffing reductions. • ISFSI only staffing levels should be evaluated for potential reductions.	• Reduced security non-officer headcount during ISFSI only period and reduced security costs by $42 million, excluding contingency. • Project team will evaluate spent fuel pool cooling times.
Waste Disposal	• No weaknesses identified with waste disposal costs.	N/A

4 The HBA, "Independent review of Diablo Canyon Power Plant Decommissioning Cost Estimate and Schedule," dated December 2018 is PG&E Prepared Testimony, Chapter I, Attachment A.

TABLE 1-1
HIGH BRIDGE ASSOCIATES STRENGTHS/FINDINGS AND PG&E RESPONSE
(CONTINUED)

Subject Area	Findings	PG&E Response
RPV and Internals Segmentation	• RPV Internals segmentation durations are too short based on Zion operating experience.	• Increased RPV Internals segmentation durations to match Zion's successful second implementation and increased costs by $14 million excluding contingency.
Building Demolition/ Breakwater Removal	• Building demolition schedule could be optimized to reduce mobilization costs. • Breakwater demolition plan (sea-based vs. land-based) is not optimal and significant cost savings could be achieved.	• Project team will continue to refine building demolition strategies and scheduling for cost efficiencies. • Project team will evaluate alternate breakwater demolition plan.
Systems & Area Closure	• Material estimates for this scope of work appear to be 5%-10% high.	• Project team will review, and where appropriate, material expenses will be adjusted.
Schedule	• Overall decommissioning schedule duration is longer than industry norm • Spent fuel pool cooling duration should be evaluated • Critical path is not optimal as RPV /internals segmentation and breakwater work should not be on critical path. • Duration to start of power block demolition is longer than industry norm.	Project team will evaluate spent fuel pool cooling times. • Moving RPV/internals segmentation scheduling for removal off of critical path. • Breakwater demolition plan and scheduling for removal from critical path.
Project Staffing	• Overall staffing plan is reasonable. • Staffing analysis is detailed, flexible, and by department. • Sufficient staff estimated for licensing and permitting activities. • Minor staffing changes recommended including additional Engineering staff.	• Incorporated majority of recommended staffing changes including additional Engineering staff. Increased costs by $28 million excluding contingency.
Contingency	• Line by line contingency analysis should be performed and utilize probabilistic modeling techniques.	• Implemented line-by-line analysis, resulting in a reduction of overall contingency from 25% to 20.6% and a reduction of $175 million. • Project team will evaluate the use of additional recommended contingency analysis.

4. Funding the DCPP ND Trust Now is Essential and in the Best Interest of Customers

Funding of the DCPP NDT beginning in 2020 is essential and in the best interest of customers. If the Commission does not approve the reasonable cost to decommission Diablo Canyon in this proceeding, the ultimate cost to customers for decommissioning will increase significantly. Firstly, delaying customer contributions to the NDT eliminates the benefits of compounded earnings. Secondly, under IRS regulations, contributions beyond 2025 to a non-qualified trust and must be grossed up for taxes, costing customers 38 percent more.

During 2003-2019, customer contributions to the NDT have been $32.4 million in total. As a result, there is large disconnect between the funds available in the NDT and the reasonable cost to decommission DCPP. Specifically, PG&E has nearly $3.2 billion in the NDT for decommissioning and needs approximately $1.6 billion (2017$) more from customers to fully fund decommissioning activities. PG&E proposes that customer contributions for decommissioning restart in 2020 and conclude at the end of 2025. This will ensure that those customers who benefit from the clean, reliable and affordable energy produced by DCPP will be responsible for supporting its decommissioning. It will also ensure compliance with California and federal laws requiring the reasonable costs of decommissioning be funded prior to the closure of a nuclear power plant.

As noted above, extending the funding period beyond 2025 would increase customer costs even further, as the tax benefits of contributing to a qualified trust may no longer be available to PG&E.[5] Under U.S. Department of Treasury Regulations, the funding period for a qualified trust ends on the last day of the estimated useful life of a nuclear power plant that has been included in rate base for ratemaking purposes. Therefore, tax efficient contributions to a qualified trust may only be made until such time as the plant is taken out of service and removed from rate base. To quantify the impacts to customers on an illustrative basis, for every $1 of DCE cost

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[5] Pursuant to Section 468A of the U.S. Internal Revenue Code (IRC), PG&E's contributions to a qualified trust are deductible from income in the year the contribution is made, provided the taxpayer receives a Schedule of Ruling Amounts from the IRS.

that is disallowed or for which recovery is deferred beyond 2025 and then funded to a non-qualified trust, customers will pay $1.62 or 62 percent more, representing a 38 percent increase from the loss of tax benefits and a 24 percent increase from the loss of six years of earnings, assuming average annual trust performance. Further, the California Nuclear Facility Decommissioning Act of 1985 ("Act") provides that "the expenses associated with decommissioning *shall* be paid from [ND Trust] funds"[6] and the Commission must permit PG&E to make the "maximum contribution to the fund…deductible…for tax purposes."[7] The Commission has determined: "Section 8325(c) requires us to ascertain the maximum level of contributions deductible for tax purposes and to authorize them in rates."[8]

This filing describes for the Commission and stakeholders a DCE for DCPP that realistically presents what the actual decommissioning process and associated costs will be PG&E urges the Commission to recognize that decommissioning of DCPP is imminent, and the NDT must be funded to support timely decommissioning. The Commission should now adopt the requested revenue requirement to fund decommissioning planning over the next six years and a revenue requirement for trust contributions that ensures adequate funding to decommission DCPP. Timely action on these proposals is necessary to avoid higher costs to customers.

5. The Commission Should Approve the HBPP DCE and Find the Decommissioning Costs Presented in This Application Reasonable

The HBPP DCE covers the period from January 2019 through 2033, including: completion of final site restoration (FSR); HBPP radiological decommissioning; termination of the HBPP Title 10 of the Code of Federal Regulations (10 CFR) Part 50 license; management of SNF/GTCC waste in the HBPP ISFSI; HBPP ISFSI decommissioning after the SNF/GTCC waste has been moved to an off-site facility; and FSR and termination of the ISFSI 10 CFR Part 72 license.

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6 Public Utilities Code (Pub. Util. Code) §8328 (emphasis added).

7 Pub. Util. Code § 8325(c).

8 D.00-02-046, mimeo, p. 371.

The updated total HBPP decommissioning cost is $1.1 billion (2018$), with a cost to complete as of January 1, 2019 of $182.5 million. This represents a $16.1 million (2018$) increase from the forecast approved in the 2015 NDCTP.

By the end of 2018, PG&E expects it will have successfully completed the majority of the Civil Works Phase, a major phase of HBPP decommissioning. Decommissioning HBPP has presented a number of challenges due to the unique design and construction of the plant; radiological activation and contamination left from the early operation of the facility; and difficult site conditions. PG&E is very proud to have completed this work safely, on schedule, within approved cost estimates, and without radiological incident. HBPP was awarded the annual Shermer L. Sibley Award six times, the most prestigious PG&E award an organization can earn in recognition of its safety achievements.

PG&E presents for review and approval $400.2 million in actual costs for completed work performed between 2012 and 2018.

B. Cost Estimates and Rate Request

1. Revenue Requirement

Based on the results of PG&E's recent analysis of the cost of pre-shutdown decommissioning activities, the value of the NDT and the expected cost to complete decommissioning of HBPP and decommission DCPP Units 1 and 2, PG&E seeks authorization to recover through CPUC-jurisdictional rates commencing January 1, 2020:

- $30.3 million annual revenue requirement for the 3-year period 2020-2022 for DCPP decommissioning planning activities through an annual expense only revenue requirement, and $44.0 million annual revenue requirement for the 2-year period 2023-2024. As described in PG&E's testimony, planning costs are included in the total decommissioning cost estimate, but they were not included in the calculation of the revenue requirement to fund the DCPP NDT.[9]

- $383.7 million annual revenue requirement for contributions to the tax qualified DCPP NDT, as adjusted by advice letter filing following a final decision in this proceeding.
- $3.9 million annual revenue requirement for contributions to the tax qualified HBPP NDT, as adjusted by an advice letter filing following a final decision in this proceeding. PG&E is not seeking a further annual revenue requirement for HBPP Safe Storage (SAFSTOR)[10] beyond what was adopted in the 2015 NDCTP Decision.

These individual elements result in a total estimated annual CPUC-jurisdictional revenue requirement for ND of $417.9 million in 2020,[11] which is $350.1 million more than PG&E's 2019 authorized decommissioning revenue requirement of $67.8 million.

2. DCPP Cost Estimate

PG&E's detailed site-specific cost estimate to decommission DCPP is shown in Table 1-2.

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[9] As described in Chapter 3, PG&E is submitting a request to the U.S. Nuclear Regulatory Commission (NRC) which, if granted, would authorize PG&E to withdraw funds from the NDT to fund pre-shutdown planning activities. If the NRC grants this request, in whole or in part, PG&E will adjust its cost recovery request for these decommissioning planning costs.

[10] D.98-03-050 determined that funds for HBPP operations and maintenance (O&M) costs associated with its NRC Part 50 non-operational license, also referred to as SAFSTOR, should also be addressed within the ND proceeding.

[11] The actual revenue requirement for the DCPP and HBPP NDT funding will be determined using end-of-the-year trust fund balances for the most recent year following a final decision in this proceeding.

TABLE 1-2
DIABLO CANYON PROJECTED TOTAL COST OF DECOMMISSIOING
(THOUSANDS OF DOLLARS)

ID	Scope Description	Total
1	Program Management, Oversight, & Fees	$1,462,045
2	Security Operations	560,686
3	Waste/Transportation/Material Management (Excluding: Breakwater, Reactor Vessel/Internal Segmentation, & Large Component Removal)	855,211
4	Power Block Modifications	80,707
5	Site Infrastructure	140,972
6	Large Component Removal	166,370
7	Reactor/Internals Segmentation	332,341
8	Spent Fuel Transfer to ISFSI	235,541
9	Turbine Building	68,667
10	Aux Building	92,122
11	Containment	121,012
12	Fuel Handling Building	48,627
14	Balance of Site	80,702
15	Intake	41,654
16	Discharge	15,122
17	Breakwater	286,326
18	Non-ISFSI Site Restoration	135,075
19	Spent Fuel Transfer to United States (U.S.) Department of Energy (DOE)	24,258
20	ISFSI Demolition and Site Restoration	54,956
21	Grand Total	$4,802,395

The amount used to calculate the necessary DCPP NDT funding in this application is $4.8 billion (2017$).

The following summarizes key elements of the DCE, which are discussed in greater detail in following testimony chapters.

- Decommissioning Planning Activities: The DCE assumes that PG&E will conduct significant planning and permitting for decommissioning prior to the shutdown of DCPP Unit 1. This early planning will allow PG&E to commence decommissioning immediately upon shutdown and will result in significant cost savings to customers compared to conducting these planning and permitting activities after shutdown. PG&E is requesting a separate revenue requirement to fund these activities as incurred.
- Disposition of Breakwater: The breakwater at DCPP is a substantial structure with significant removal challenges. However, PG&E's California State Lands Commission (CSLC) lease requires PG&E to remove the DCPP intake structure, breakwaters, and discharge

structure at the termination of the lease. Thus, the cost of complying with the CSLC lease must be included in the estimated cost to decommission DCPP. While PG&E believes that removal of the intake and discharge structures is warranted, PG&E, in consultation with stakeholders and relevant agencies, is evaluating possibilities for repurposing or leaving the breakwater in place if the CSLC lease can be amended.

- Building Demolition and Waste Disposal: Waste disposal costs are significant costs associated with decommissioning. These costs are based largely on the volume of material generated during decommissioning and the disposal costs for that material. PG&E's current plan includes several proactive steps designed to minimize the total amount of waste, including: waste reduction through building removal techniques, segregating higher-level wastes to minimize the amount of high level radiological waste versus lower level radiological waste, maximizing re-use and recycling waste to avoid the costs of off-site disposal, and utilizing the most cost-effective waste disposal options.
- Security: Security is an integral component of decommissioning, governed by NRC regulations, and consists primarily of security staffing costs. Using PG&E's existing NRC-approved security plan and staffing levels as a starting point, PG&E conducted a comprehensive review including using state-of-the-art software and site walk downs of DCPP security requirements pre- and post-unit shutdown. PG&E's post-shutdown security plan has been independently reviewed by a third-party expert. PG&E identified several cost mitigation measures, including: (1) plant modifications which will reduce the number of necessary security personnel and (2) affirmative steps to be taken prior to the beginning of each phase of decommissioning to reduce the required number of security personnel.
- Spent Nuclear Fuel: Costs associated with SNF are a significant component of the DCE. The DCE assumes that: (a) PG&E will complete transfer of SNF and GTCC waste from the spent fuel pool to the ISFSI seven years after DCPP Unit 2 shutdown, (b) the DOE will

begin collecting SNF in the nuclear industry in 2031, and (c) the DOE will specifically commence picking up SNF at DCPP in 2038.

- Regulatory Approvals and Permits: PG&E will require many regulatory approvals and permits to decommission DCPP. These are critical items and require close coordination with federal, state, and local agencies that are essential to the success of DCPP decommissioning. Delays in obtaining (or failure to obtain) approval and/or possible regulatory conditions could significantly impact estimated costs.

3. HBPP Cost Estimate and Reasonableness Review

In 2018 PG&E is completing a major phase of decommissioning HBPP, on schedule and within budget. There are no changes to the HBPP DCE approved in the 2015 NDCTP other than: (1) a decrease of $9.3 million (2018$) due to realized cost savings of $7.3 million in Canal Remediation Disposal and $2.0 million in EPC Services; and (2) an increase of $25.1 million (2018$) related to the assumption that PG&E will incur an additional three years of spent fuel management costs based on an assumed delay from 2028-2031 in the DOE commencing pick up of SNF/GTCC waste. The estimate to complete the remaining decommissioning work at HBPP as of January 1, 2019, is $182.5 million (2018$); and the total cost to decommission HBPP is $1.1 billion (nominal/2018$).

PG&E also demonstrates in this testimony that the following are reasonable: $400 million in decommissioning projects at HBPP completed since PG&E filed its 2015 NDCTP application; PG&E's efforts to retain and utilize qualified personnel for decommissioning activities at HBPP; and the variances in actual versus forecast SAFSTOR expenses from the prior period.

C. Legislative and Regulatory Requirements

The Nuclear Facility Decommissioning Act of 1985[12] requires that electrical utilities owning or operating a nuclear facility in California establish an externally managed, segregated fund which qualifies for a tax deduction, pursuant to Section 468A of the U.S. IRC (tax qualified fund), and that the Commission

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12 California Pub. Util. Code Sections 8321 *et seq.*

authorize the utility to collect sufficient revenues in rates to make the maximum deductible contributions to the fund, and any separate non-qualified fund, so that the expenses associated with decommissioning of nuclear facilities can be paid from the funds.[13]

Utilities must periodically revise their ND cost estimate studies to ensure that the decommissioning cost estimates take into account changes in regulation, technology, economics, and the operating experience of each nuclear facility.[14] To the extent the monies available in the trusts for decommissioning are insufficient to pay for all reasonable and prudent decommissioning costs, the Commission must authorize the utility to collect these charges from its customers.[15]

In D.95-07-055 (PG&E's 1995 General Rate Case (GRC)), the Commission established investment guidelines for the NDT funds and reporting requirements for determining those costs. One of those requirements is that engineering cost studies and ratepayer contribution analyses continue to be performed every three years. In D.96-12-088, the Commission determined that in the absence of GRCs, the NDCTP would establish the annual revenue requirement for ND expense over a 3-year period, and D.05-05-028 determined that PG&E should file applications for decommissioning in the NDCTP every three years, even though GRCs continued to determine utility rates.

PG&E filed its first NDCTP application on March 15, 2002. Joint hearings were held on common issues with Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E), although the proceedings were not consolidated. The Commission issued a decision in PG&E's first NDCTP on October 2, 2003 (D.03-10-014).

The three California utilities again filed NDCTP applications on November 10, 2005. The Assigned Commissioner's scoping ruling concluded that the applications of all three utilities should be consolidated, rather than merely being coordinated. The Commission issued a decision in the 2005 NDCTP on January 11, 2007 (D.07-01-003). The utilities' 2009 NDCTP

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13 Pub. Util. Code Sections 8325, 8328.

14 Pub. Util. Code Section 8326.

15 Pub. Util. Code Section 8328.

applications filed on April 3, 2009 were again consolidated. The Commission issued a 2009 NDCTP Phase 1 decision on August 5, 2010,[16] a subsequent decision adopting the Recommendations of the Independent Panel on Nuclear Decommissioning Costs, Estimates, Assumptions, and Format on July 14, 2011,[17] and a 2009 Phase 2 decision on January 24, 2013.[18]

The 2012 NDCTP applications were filed with the Commission on December 21, 2012, and again consolidated. On June 17, 2013, the Commission bifurcated the proceeding with the Phase 1 proceeding addressing the HBPP cost study, the SAFSTOR O&M forecast and reasonableness review of completed HBPP decommissioning activities; and Phase 2 addressing the DCPP, San Onofre Nuclear Generating Station (SONGS) 1, 2 and 3, and Palo Verde decommissioning cost studies and all remaining financial assumptions. The Commission issued the Phase 1 final decision on February 27, 2014[19] and the Phase 2 final decision on December 18, 2014.[20]

The utilities filed their 2015 NDCTP applications on March 1, 2016. The Commission declined to consolidate the 2015 NDCTP applications on the grounds that there was an insufficient relationship between the facts or law to be applied in the PG&E application and the facts and law to be applied in the SONGS applications.[21] The Commission issued its decision in PG&E's 2015 NDCTP on June 1, 2017.[22]

D. Support for Request

1. Testimony

PG&E's request is presented and supported in testimony as follows:

- <u>Chapter 1 – Introduction and Policy</u>: This chapter summarizes PG&E's overall request, provides the legislative and regulatory requirements for

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[16] D.10-07-047.

[17] D.11-07-003.

[18] D.13-01-039.

[19] D.14-02-024.

[20] D.14-12-082.

[21] *Joint Scoping Memo and Ruling Of Assigned Commissioner And Administrative Law Judge*, issued July 15, 2016 in Application (A.) 16-03-006.

[22] D.17-05-020.

filing this application, explains the purpose of each of the subsequent testimony chapters and identifies where PG&E's compliance with prior Commission directives is addressed.

- Chapter 2 – Diablo Canyon Power Plant Preliminary Decommissioning Preparation: This chapter addresses Commission approval of PG&E's decision to cease operations at DCPP upon license termination, preliminary planning for decommissioning, development of the site-specific DCPP DCE, and PG&E's efforts to characterize and reduce site contamination prior to permanent shutdown.
- Chapter 3 – Diablo Canyon Power Plant Decommissioning Planning Activities 2019-2024: This chapter identifies DCPP decommissioning planning activities which PG&E proposes to conduct between 2019 and 2024 and associated costs, identifies the reason why these costs cannot now be recovered from the NDT, proposes a separate rate recovery mechanism, and identifies associated customer benefits.
- Chapter 4 – Diablo Canyon Power Plant Site-Specific Decommissioning Cost Estimate: This chapter presents the results of the site-specific DCE prepared by PG&E for decommissioning DCPP.
- Chapter 5 – Diablo Canyon Power Plant Lands And Related Matters: This chapter describes DCPP lands and land ownership; provides preliminary information on the public stakeholder process; report out on PG&E's discussions with state agencies regarding the disposition of the breakwaters; provides the status of PG&E's consultation with specified state agencies with respect to Executive Order (EO) D-62-02 and the DCPP breakwaters; and identifies all environmental reviews required for DCPP decommissioning.
- Chapter 6 – Spent Nuclear Fuel: This chapter presents an analysis of the feasibility of both pre- and post-shut down acceleration of dry cask loading at DCPP, costs for expediting dry cask loading, an updated assessment of the commencement of DOE SNF pickup, the status of PG&E's DOE settlement and a report on return of DOE net settlement payments to customers.
- Chapter 7 – Diablo Canyon Power Plant Completed Project Reasonableness Review Procedures: This chapter describes how

PG&E will track decommissioning expenditures for future reasonableness review and identifies specific decommissioning milestones and schedule.

- Chapter 8 – Humboldt Bay Power Plant Unit 3 Updated Nuclear Decommissioning Cost Estimate: This chapter presents the results of the HBPP decommissioning cost study prepared by PG&E's HBPP staff. This testimony provides the current cost and schedule estimates, describes updates from the estimate authorized in the 2015 NDCTP Decision and discusses the status of remaining decommissioning work at HBPP. This chapter also explains that the 2015 NDCTP decision authorized a 2019 annual revenue requirement of $4.4 million for SAFSTOR expenses, and that PG&E will not be seeking a further SAFSTOR revenue requirement for 2020 and beyond.
- Chapter 9 – Humboldt Bay Power Plant Unit 3 Completed Project Reasonableness Review Testimony: This chapter demonstrates the reasonableness and prudence of $400 million of decommissioning activities at HBPP completed through December 31, 2018. If necessary, PG&E will update this testimony to reflect final year-end amounts. This chapter also demonstrates that PG&E has made all reasonable efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely and efficiently pursue decommissioning, and accounts for the differences between the forecast and actual SAFSTOR expenses for 2016-2018.
- Chapter 10 – Contributions for Funding the Diablo Canyon Power Plant Units 1 And 2 And Humboldt Bay Power Plant Unit 3 Nuclear Decommissioning Trust: This chapter presents PG&E's revised forecast of annual contributions to the nuclear facilities qualified decommissioning master trust for DCPP and HBPP beginning January 1, 2020. In addition, this chapter reviews the updated assumptions used to forecast nominal decommissioning costs, Trust balances and annual contributions including escalation rates, estimated rates of return on invested funds and equity turnover rates to ensure that adequate funds will be available for decommissioning activities.

- Chapter 11 – Trust Contribution and Planning Activities Revenue Requirements: This chapter presents the calculation of the revenue requirement for pre-shutdown decommissioning planning activities, which will be recovered separately as incurred, and not funded to the DCPP NDT. It also explains PG&E's proposed ratemaking treatment of the transition from Diablo Canyon Decommissioning Planning Memorandum Account pending before the Commission in A.18-07-013, and the steps PG&E will take in the event the NRC grants PG&E an exemption with respect to early withdrawal of decommissioning funds from the DCPP NDT. This chapter also presents the revenue requirements needed to fund PG&E's NDT beginning January 1, 2020. These revenue requirements are based on the contributions presented in Chapter 10.

2. Compliance with Prior Commission Directives

D.17-05-020 directed PG&E to provide testimony in its next NDCTP to demonstrate that it continues to comply with the reporting requirements adopted in prior NDCTP proceedings.[23] This section identifies each prior Commission directive and where in the testimony it is addressed.

- Organize a meeting within 60 days of the date D.17-05-020 was issued and develop a cost categorization structure for DCPP which: (1) facilitates tracking decommissioning expenditures by major subprojects within a decommissioning phase; (2) allows for comparison to previously approved estimates of activities, costs, and schedule; and (3) requires written record of key decisions about cost, scope, or timing of a major project or activity.[24] PG&E's proposal is presented in Chapter 7.
- Report the *pro rata* share of funds accumulated for NRC license termination and provide copies of the most recent funding assurance letters sent to the NRC.[25] A copy of PG&E's most recent funding assurance letter for DCPP is included as PG&E Prepared Testimony,

[23] D.17-05-020, p. 64.

[24] D.17-05-020, Ordering Paragraph (OP) 3, OP 4.

[25] D.14-12-084, OP 10; D.17-05-020, p. 64.

Chapter 1, Attachment B, and a copy of PG&E's most recent funding assurance letter for HBPP is included as PG&E Prepared Testimony, Chapter 1, Attachment C.

- Include a comparison of the current proposed decommissioning cost estimate with the last two prior estimates approved through the NDCTP.[26] The comparison for DCPP is provided in Chapter 4, Section D, and the comparison for HBPP is provided in Chapter 8, Table 8-1.
- Provide with future NDCTP applications a common format in summary form identifying certain specified assumptions and trust fund forecasts for PG&E, SCE, and SDG&E.[27] Consistent with prior NDCTPs, the required information is provided as Exhibit A to PG&E's application. PG&E has obtained the information relevant to SCE and SDG&E directly from those companies.
- Submit a summary of actual NDTF performance covering the previous three years and include a comparison with the prior NDCTP forecast performance.[28] This information is included in Chapter 10, Sections I and J.
- Document PG&E's efforts to characterize and reduce site contamination at DCPP prior to permanent shutdown.[29] PG&E's testimony is included in Chapter 2, Section D.
- Provide a comparison of industry wide security costs and explain site-specific issues that would increase the security needs at DCPP.[30] PG&E's testimony is included in Chapter 4, Section E.
- Provide a summary and results of consultation with the California Coastal Commission, State Lands Commission, Department of Public Health, California State Water Resources Control Board, and the Department of Toxic Substances Control concerning the application of

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26 D.17-05-020, p. 66.

27 D.11-07-003, OP 2; D.17-05-020, p. 64.

28 D.13-01-039, OP 12; D.17-05-020, p. 65.

29 D.17-05-020, p. 69.

30 D.17-05-020, p. 71.

California Governor EO D-62-02 to disposal of construction debris and whether the DCPP breakwater will be required to be removed.[31] This testimony is provided in Chapter 5, Section E.

- Take no action with respect to the disposition of DCPP facilities and surrounding lands before completion of a future process including a public stakeholder process.[32] PG&E's testimony addressing this issue is provided in Chapter 5, Section D.
- Provide an assessment for expediting dry cask loading at DCPP, including both pre-shutdown and post-shutdown options and costs for expediting dry cask loading.[33] This testimony is provided in Chapter 6, Section B.
- Provide an assessment of when SNF will be picked up from HBPP and DCPP, including any change in circumstance as to any progress with approvals for a permanent or long-term off-site repository for SNF; and a report regarding the status of the settlement between PG&E and the DOE concerning reimbursement for SNF management costs and how PG&E is accounting/crediting funds back to ratepayers.[34] This testimony is provided in Chapter 6, Sections D and E.
- File annually Tier 2 ALs [advice letters] for in the trust disbursement showing information supporting the requested disbursement tied to the nuclear decommissioning cost estimate and expenditures and related progress toward specific major milestones in the decommissioning process.[35] HBPP demonstrates its compliance in Chapter 8, Section H. As of the date of this application, DCPP has not commenced withdrawing funds from the NDT.

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[31] D.17-05-020, OP 7.

[32] D.18-01-022, OP 13.

[33] D.17-05-020, OP 5.

[34] D.17-05-020, p. 66 and OP 10.

[35] D.17-05-020, OP 6.

- File after-the-fact reasonableness reviews of decommissioning expenditures for HBPP in subsequent NDCTPs.[36] This testimony is provided in Chapter 9.
- Demonstrate that PG&E has made all reasonable efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely, and efficiently pursue any physical decommissioning-related activities for the nuclear generation facilities under its control.[37] Since DCPP has not commenced physical decommissioning, this Testimony with respect to HBPP is provided in Chapter 9, Section F.
- Maintain a written record of decisions about the cost, scope or timing of major decommissioning projects or activities at HBPP that results in a variation from the prior estimate by +/-10 percent.[38] This testimony is provided in Chapter 8, Section G.
- Track and explain any differences between actual and forecast SAFSTOR O&M expenses.[39] This testimony is provided in Chapter 9, Section G.

E. Effective Date of New Revenue Requirements

PG&E requests the Commission permit PG&E to recover $178.9 million of costs associated with decommissioning planning activities for 2019-2024 through an annual expense only revenue requirement of $30.3 million for the period 2020-2022 and an annual expense only revenue requirement of $43 million for the period 2023-2024.

PG&E requests the Commission adopt January 1, 2020, as the effective date for the revised annual trusts revenue requirements proposed by PG&E in this application. The Commission requires the utilities to file NDCTP applications on a triennial basis, with the evidently intended result of revising revenue requirements every three years.[40] Since the 2015 NDTCP established annual revenue requirements commencing January 1, 2017, an effective date of

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[36] D.17-05-020, OP 9.

[37] D.14-02-024, OP 5; D.14-12-084, OP 4; D.17-05-020, OP 2.

[38] D.14-02-024, OP 4.

[39] D.14-02-024, OP 3.

[40] D.95-07-055, OP 7 and D.05-05-028, at 1.

January 1, 2020 would result in a corresponding three-year revenue requirement for the 2018 NDCTP.[41]

F. Request for Findings

As described above and in the subsequent chapters, PG&E requests that the Commission:

- Authorize PG&E to establish the Diablo Canyon Decommissioning Balancing Account and to recover through CPUC-jurisdictional rates commencing January 1, 2020, a $30.3 million annual, expense only revenue requirement for the 3-year period 2020 to 2022 and a $44.0 million annual, expense only revenue requirement for the 2-year period 2023 to 2024 for funding pre-shutdown decommissioning planning activities.
- Authorize PG&E to collect through CPUC jurisdictional electric rates an annual revenue requirement commencing January 1, 2020, of $383.7 million for funding the DCPP tax qualified trust, as adjusted by advice letter filing immediately following a final decision in this proceeding.[42]
- Authorize PG&E to continue to collect through CPUC-jurisdictional electric rates an annual revenue requirement commencing January 1, 2020, of $3.9 million for funding the HBPP tax qualified trust, as adjusted by advice letter filing immediately following a final decision in this proceeding.
- Find that the decommissioning cost estimates and associated trust contribution analyses are reasonable and present the most up-to-date information on the potential cost to decommission DCPP and HBPP.
- Approve PG&E's proposed Milestone Framework for tracking and reviewing actual decommissioning expenditures at DCPP.
- Find that the $400 million in costs incurred for completed decommissioning activities at HBPP are reasonable and prudently incurred.
- Find that the variances in actual versus forecast SAFSTOR expenses for 2016-2018 are reasonable.

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41 Under Treasury Regulations, the Internal Revenue Service requires that any increase in the level of PG&E's contributions to the Diablo Canyon qualifying trusts for 2020 be requested by ruling and actually contributed to the qualified trusts, no later than March 15, 2021. See Treasury Regulation 1.468A-2(c)(1) and 1.468A-3(e)(1)(v).

42 The annual contributions to be updated as described in the following chapters.

- Find that PG&E’s efforts to retain and utilize qualified personnel for physical decommissioning activities at HBPP are reasonable;
- Find that PG&E is in compliance with prior CPUC NDCTP decisions’ requirements as identified in Section B.2. above.
- Authorize PG&E to update the nuclear decommissioning revenue requirements for adjustments to the cost of capital, Revenue Fees and Uncollectibles, and tax parameters as adopted in PG&E’s 2019 Cost of Capital and 2020 GRC final decision.
- Authorize PG&E to implement the new revenue requirement through the next available consolidated electric rate change following a final decision for this application.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

DIABLO CANYON POWER PLANT PRELIMINARY

DECOMMISSIONING PREPARATION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
DIABLO CANYON POWER PLANT PRELIMINARY DECOMMISSIONING PREPARATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
DIABLO CANYON POWER PLANT PRELIMINARY DECOMMISSIONING PREPARATION

A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) decision to retire Diablo Canyon Power Plant (DCPP or Diablo Canyon) upon current license termination, PG&E's preliminary decommissioning planning and preparation of the DCPP Decommissioning Cost Estimate (DCE), and to respond to the California Public Utilities Commission's (CPUC or Commission) directive that PG&E document its efforts to characterize and reduce site contamination at DCPP prior to permanent shutdown.

B. Commission Approval of Agreement to Retire Diablo Canyon

In 2016, PG&E entered into an agreement referred to as the Joint Proposal. In the Joint Proposal, PG&E agreed to withdraw the pending application at the Nuclear Regulatory Commission (NRC) to renew the operating licenses for DCPP Units 1 and 2 for an additional twenty years and, instead, retire DCPP upon the expiration of the current operating licenses. PG&E also agreed to submit to the Commission a site-specific DCE for DCPP no later than the filing date for the 2018 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP). In addition to these commitments, the parties agreed to: (1) procurement of three tranches of greenhouse gas free resources to partially replace the output of DCPP; (2) retention, retraining, and severance programs for DCPP employees; (3) the Community Impacts Mitigation Program (CIMP), a program that would provide funding to the local community to mitigate the economic impact of the plant's retirement; and (4) rate recovery of various costs, including amounts spent for environmental reviews and PG&E's then-suspended NRC license renewal application.

The Joint Proposal contemplated that the site-specific decommissioning study would incorporate the costs of the employee retention program, CIMP, the plan for expedited post-shut-down-transfer of spent fuel to dry cask storage, and a plan to continue certain emergency planning activities, including maintenance of the public warning sirens and funding of community and state wide emergency planning functions, until the termination of the Part 50 license, subject to Commission approval and funding of these elements of PG&E's revised DCPP decommissioning study.

PG&E requested Commission approval of the Joint Proposal in an Application filed in August 2016. In January 2018, the Commission issued a decision approving certain elements of the Joint Proposal. Among other things, the Commission approved PG&E's proposal to retire DCPP upon the expiration of the current operating licenses and commitment to file a site-specific DCE for DCPP in the 2018 NDCTP. The Commission also directed PG&E to establish and implement a public stakeholder process before taking any action with respect to disposition of DCPP facilities and surrounding lands.[1]

However, the Commission rejected the CIMP in its entirety and directed that a revised employee retention program be recovered from customers in generation rates. Subsequently, in Senate Bill (SB) 1090, the California legislature directed the Commission to allow full funding of the employee retention program and the CIMP through an advice letter filing at the Commission.

Consistent with Decision (D.) 18-01-022 and SB 1090, this DCE does not include the costs of the employee retention program or the CIMP. It does include the cost of the plan for expedited post-shut down transfer of spent fuel to dry cask storage and the cost of the plan to continue certain emergency planning activities until the termination of the Part 50 license.

C. Development of the Decommissioning Cost Estimate

1. Preliminary Planning

In mid-2016, PG&E initiated a pre-project planning process to fully identify and understand the options available for decommissioning DCPP. This process concluded with the issuance of a Pre-Project Plan (PPP). The PPP is a high-level outline of the necessary planning activities to fully transition from operational to decommissioning status, avoiding the interim status many facilities enter into post-shutdown, safe storage status.

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[1] D.18-01-022, Ordering Paragraph 13.

The PPP development team consisted of 12 individuals with more than 100 years of combined experience in decommissioning, including PG&E management personnel with direct decommissioning experience with Humboldt Bay Power Plant (HBPP) Decommissioning and contracted decommissioning industry subject matter experts (SME). Internal and external SMEs reviewed the PPP, as did PG&E executive management. The PPP was completed in December 2016. Its primary recommendation was that the best way to develop a DCPP site-specific DCE was through preparation of Project Management Plans (PMP) and studies.

2. Planning Team and Work Scope

PG&E initiated detailed preparation of critical planning elements over 24 months to develop the site-specific DCE for the 2018 NDCTP. PG&E did not rely on a generic nuclear industry decommissioning unit cost factor methodology, but instead used a dedicated team of nuclear, decommissioning, and DCPP experts to form a decommissioning plan, schedule, and associated cost estimate. This "bottom up" approach included the following phases and used targeted industry SMEs and third-party reviews of decisions, plans, assumptions, and cost estimates:

- Decommissioning planning team and work scope;
- Request for Proposal (RFP) process, including modification of the PPP—recommended roadmap to better utilize vendor expertise and current industry practices, and to reduce costs;
- Benchmarking; and
- Preparation of PMPs and studies.

The DCPP decommissioning planning team was assembled under the leadership of the Senior Director of Decommissioning, who currently leads the decommissioning activities at HBPP and has experience from numerous other sites throughout the nuclear industry. The planning team includes experts in specific fields who understand the complexity and multi-discipline requirements for a project of this scale. This includes PG&E leadership, decommissioning-experienced personnel, DCPP operating plant departmental personnel, specialty contractors, corporate legal, finance, and accounting. This blend of knowledge and experience yielded an effective team to develop the decommissioning plan for DCPP. The DCPP decommissioning planning team focused on:

- Developing the processes needed to control the flow of planning, such as decommissioning programs and administrative procedures;
- Identifying those studies and PMPs that could be developed internally and conducting the associated analyses;
- Identifying those studies and PMPs to be bid out and awarded externally to experienced vendors with the applicable expertise; and
- Reviewing and accepting vendor work products to ensure adequacy for inclusion in the DCE.

3. RFP Process

The DCPP decommissioning planning team developed RFPs for the activities requiring external support or independent evaluation from vendors to obtain the most recent industry experience and techniques. This included identifying and describing the technical scope specifications of activities and cost elements followed by an analysis of each item identified. In the RFPs, PG&E requested that vendor work products contain each scope item described in terms of duration, resource requirements, and cost to complete the scope of work so that it could be used in the DCE.

PG&E invited nearly 70 vendors with knowledge and expertise in nuclear, decommissioning, construction, demolition, environmental, and regulatory to participate in the RFP process for awarding decommissioning planning work at a Supplier Orientation in May 2017. The desire was to utilize the most qualified vendors to develop the foundation of a defendable and executable DCE. Initially, as outlined in the PPP, PG&E intended to issue ten separate RFP “bundles” that grouped together PMPs and studies with similar scopes for work. However, after additional PG&E consideration, feedback from vendors that attended the Supplier Orientation, and feedback during the RFP process, PG&E decided to restructure and further consolidate the work scopes into six RFP bundles. Doing so would allow for a single vendor to coordinate the various interfaces and integration of the individual work scopes, reducing the time and effort to develop the PMPs and studies and, as a result, reducing the overall costs for the work. This also enabled PG&E to develop a more integrated and efficient overall decommissioning strategy and implementation plan. The re-structure and re-bundling of work scopes in RFPs was implemented before several contracts were issued, saving PG&E time in negotiations and contract issuance, reducing DCE vendor development costs, and allowing vendors to bid more efficiently.

Vendors that were ultimately awarded contracts had specialty sub-contractors supporting work product development. In addition to the re-bundled PMPs and studies, PG&E awarded contracts to non-bundle vendors for those PMPs and studies that required limited coordination with other plans.

4. Benchmarking

In addition to obtaining recent industry experience from vendors through their development of PMPS and studies discussed below, PG&E completed benchmarking with those sites that either completed or are still completing decommissioning. It used a two-tiered approach. First, it conducted an email benchmark survey with the following sites:

- Crystal River (Florida)
- Humboldt Bay (California)
- Kewaunee (Wisconsin)
- Oyster Creek (New Jersey)
- Rancho Seco (California)
- SONGS (California)
- Trojan (Oregon)
- Vermont Yankee (Vermont)
- Zion (Illinois)

Based on the survey responses, PG&E then determined which sites would provide experience that could be applied at DCPP and visited them to conduct in-person benchmarking. This thoughtful selection of in-person benchmarking was completed so that funds were only expended on those benchmarking trips that would provide useful insights for DCPP. In-person benchmarking took place at the following sites:

- Crystal River
- Oyster Creek
- SONGS

- Vermont Yankee
- Zion

The insights gained from PG&E's industry benchmarking included the areas of staffing, spent fuel management, waste transportation, security, cost control, risk, and community engagement.

In addition, as part of the work scope requirements for developing the various PMPs and studies, vendors included their own benchmarking research and insights.

5. Project Management Plans and Studies

PMPs and studies were prepared to establish the site-specific baseline for decommissioning activities, costs, and an executable schedule. PMPs were prepared to develop the plans for major decommissioning evolutions, while studies were prepared to gather information on specific topics. This thoughtful analysis allowed PG&E to evaluate options for optimal cost performance.

The PMPs established cost estimates for key programs (e.g., waste and transportation), projects (e.g., reactor segmentation, large component removal, and building demolition) and engineering activities (e.g., cold and dark for the power distribution at the site during decommissioning and spent fuel pool island) for the DCE in the 2018 NDCTP application. They serve two purposes - establish costs for the DCE and to guide the development of bid specifications for specific decommissioning work. They reflect the experience and lessons learned from decommissioning experts. Two types of PMPs were used: Programmatic PMPs to focus on program-level activity planning, and Discrete PMPs for the planning of discrete scope project elements.

The decommissioning studies addressed specific issues or concerns, such as water management issues, site infrastructure needs, and options for source term reduction. The studies identified options for executing the specified actions, provided specific technical expertise for proper sequencing, and provided a more accurate cost estimate for the activities. In many cases, the studies provided input for PMP development or for solely making a decision. Some studies, such as Future Land Use Evaluation, will be used to make financial or strategic decisions. The studies are an integral part of the development of PMPs. In conjunction with the PMPs and studies, PG&E evaluated licensing submittals, permits, procedures, and strategic work packages to help obtain the required regulatory authorizations to begin decommissioning activities as soon as practical after permanent shutdown.

Two types of studies were used—cost studies to provide the basis for cost estimates not addressed in programmatic or discrete PMPs and option assessment studies to gather information and evaluate alternatives.

Together, the PMPs and studies were used to develop the executable project schedule, which is part of the DCE. The project schedule provided not only a road map for systematic project execution but also the means by which to gauge progress, identify and resolve potential cost estimate problems, and promote accountability at all levels of the estimate. A schedule provided a time sequence for the duration of a project's activities and aided in understanding the dates for major milestones and the activities that drive the schedule. A project schedule was used as a vehicle for developing a project cost baseline. Among other things, scheduling allows project management to decide between possible sequences of activities, determine the flexibility of the schedule according to available resources, and predict the consequences of action or inaction on events.

The cost estimate was developed in phases and consists of both discrete and unassigned costs. Discrete costs are those expenses that are directly attributable to an activity with specific completion criteria such as Reactor Pressure Vessel removal or establishing a Spent Fuel Pool Island. Unassigned costs are expenses not easily attributed to a discrete work scope such as staffing, waste, and transportation costs.

After each cost was allocated, the costs were grouped into categories and time phased using the project schedule.

The DCE includes the cost of completed decommissioning activities and forecasts costs for planned decommissioning activities. As decommissioning progresses, decommissioning decisions will be made on contracting strategies; decommissioning strategies and work sequences; selection of decommissioning technologies; and final site end state. DCE submittals will be updated and submitted to the Commission and/or

NRC to reflect decommissioning decisions and changes as decommissioning approaches.

The planning efforts described above compiled high-level, executable plans; studies of specific activities or attributes anticipated during decommissioning; detailed guidance in the form of PMPs for specific scopes of work; an executable schedule; administrative processes that defined the interactions with regulators, stakeholders, and staff; and financial processes for estimating, tracking, and reporting decommissioning costs.

D. Preliminary Site Characterization

This section responds to the Commission's directive in the 2015 NDCTP that PG&E document its efforts to characterize and reduce site contamination at DCPP prior to permanent shutdown.[2]

PG&E has reduced site contamination to the maximum extent practicable for an operating nuclear power plant site. Numerous existing regulations require minimizing, preventing, and documenting both radiological and chemical related contamination and spill events. PG&E has robust programs and initiatives in place to minimize and prevent both chemical and radiological spill events. These programs include:

- The 2006 Nuclear Energy Institute groundwater protection initiative (GPI 07-007), which establishes standards for sampling and reporting groundwater monitoring;
- The Buried Piping Program, which analyzes and inspects below-grade piping is analyzed and inspected;
- The Radiological and Environmental Monitoring Program, which monitors for radioactive contamination in the environment;
- Effluents Control Program administered by the Offsite Dose Calculation Manual, which regulates and monitors radioactive effluents;
- The Spill Prevention Countermeasure and Control Program, which catalogs and develops procedures and controls to prevent hydrocarbon spills; and
- The Storm Water Pollution Prevention Plan, which controls site exposure to rainfall and potential pollutants.

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[2] D.17-05-020, p 69.

As a result of these initiatives, PG&E makes all feasible efforts to prevent chemical or radiological contamination in the environment which could harm humans and/or the environment. If a significant spill occurs, the event is immediately documented in the corrective action program. If a spill cannot be completely cleaned up or mitigated, the event will be documented as required by 10 Code of Federal Regulations (CFR) 50.75g. Any government regulatory agency may require interim or complete cleanup of a spill or contamination event if the event could cause harm to human health or the environment.

In 2018, PG&E performed a Historical Site Assessment (HSA). This investigation collected information regarding the site history from the start of operations to the present and used the following information sources:

- Annual environmental reports
- Annual effluent reports
- Licensee event reports
- 10 CFR 50.75g files
- Groundwater sampling data
- Radiation survey data
- Area and boundary locations for radiological areas
- Corrective action reports
- Personnel interviews

The HSA identified potential non-radiological contamination such as petroleum hydrocarbons, asbestos, and lead paint, and potential radioactive contamination. Both types warrant additional investigation as part of the site characterization plan to be performed upon plant shutdown.

Detailed physical sampling and characterization cannot be accurately accomplished until DCPP Unit 1 and Unit 2 cease operation. Physical characterization of the site could be compromised in accuracy if a radiological or non-radiological event occurred while the units were still operating. If the accuracy of site characterization was questioned due to early sampling, then additional costs would be incurred for additional surveys and sampling for both radiological and non-radiological contaminants.

Further, it is not practicable or cost effective for DCPP to aggressively remove residual contamination prior to permanent shutdown. For example, residual diesel fuel oil contamination under the Unit 1 Turbine Building was discovered in 1993 following replacement of the originally installed carbon steel fuel oil tanks which had degraded. The contamination event is documented in the 10 CFR 50.75g file, as required by regulation. The diesel fuel oil contamination is stable and confined to a sand layer which is on top of an impermeable soil clay layer under the building's foundation. Decontamination would require removing a substantial portion of the Turbine Building foundation and create the potential for compromising the existing building foundation and underlying slopes. Thorough characterization and decontamination will be more efficient and less costly following cessation of plant operations.

In conclusion, PG&E is taking all appropriate steps to monitor and minimize adverse site conditions at DCPP while the plant is operational.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

DIABLO CANYON POWER PLANT DECOMMISSIONING PLANNING ACTIVITIES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
DIABLO CANYON POWER PLANT DECOMMISSIONING PLANNING ACTIVITIES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
DIABLO CANYON POWER PLANT DECOMMISSIONING PLANNING ACTIVITIES

A. Introduction

The purpose of this chapter is to describe the decommissioning planning activities necessary to support a prompt transition to physical decommissioning after shut down of Diablo Canyon Power Plant (DCPP or Diablo Canyon) Unit 1 in 2024 and Unit 2 in 2025; present the estimated cost of these decommissioning planning activities and the benefit of performing these activities over the next six years rather than waiting until after shut down to initiate planning activities; explain the United States Nuclear Regulatory Commission (NRC) regulations limiting access to the DCPP Nuclear Decommissioning Trust (NDT) for decommissioning planning activities pre-shutdown; and identify the cost estimate for decommissioning planning activities which Pacific Gas and Electric Company (PG&E) requests to recover directly from customers in retail rates through the Nuclear Decommissioning (ND) Non-Bypassable Charge (NBC).[1]

B. Immediate Transition to Decommissioning Is in the Best Interest of Customers

In Decision (D.) 18-01-022, the California Public Utilities Commission (CPUC or Commission) approved PG&E's proposal to retire DCPP Unit 1 in 2024 and DCPP Unit 2 in 2025 upon expiration of their current NRC licenses. In both that Application (A.) 16-08-006 and PG&E's 2015 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), A.16-03-006, the Commission and intervenors expressed a strong preference for prompt decommissioning of DCPP upon plant shutdown. PG&E's goal is to transition DCPP directly from operational status to decommissioning status upon

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1 PG&E submitted a request for exemption from the NRC regulations limiting access to the DCPP NDT for the cost of decommissioning planning activities pre-shutdown. If the NRC grants this request and allows PG&E to withdraw funds for decommissioning planning activities from the NDT, PG&E will modify the cost recovery proposal for these costs presented in Chapter 11.

permanent shutdown. Not only is direct transition to decommissioning status consistent with Commission and stakeholder preference, it is in the best interest of PG&E's customers because decommissioning is likely to be less expensive than Safe Storage (SAFSTOR) and the total cost of decommissioning will be reduced by prompt initiation of decommissioning activities.

To transition directly to decommissioning status upon plant shutdown, PG&E must implement decommissioning planning activities during the next six years. These planning activities are described in detail in Sections E through J of this chapter. The cost estimate for these decommissioning planning activities is $187.8 million (2017$). Table 3-1 presents the costs to implement decommissioning planning activities pre-shutdown. Though the cost to perform the decommissioning planning activities is the same whether the plant is operating or shut down, the total cost of decommissioning is greater if planning is deferred until after shutdown.

Typically, the planning effort for commercial reactor decommissioning is performed after reactor shutdown and it takes at least a year—if not longer—to reach the point when physical decommissioning can begin. Continuing planning and permitting activities during the next six years—rather than disbanding the experienced team that has been developing the site-specific DCE for DCPP when that effort is complete—would significantly shorten the overall decommissioning schedule and reduce the overall cost of decommissioning by $166.1 million. Table 3-1 presents the savings associated with implementing decommissioning planning activities pre-shutdown.

Unfortunately, the very circumstance that presents PG&E with a unique opportunity to plan and prepare for decommissioning—six years advanced notice of shutdown—limits PG&E's access to the funding necessary to implement the planning activities necessary for a direct transition to decommissioning. As explained in more detail in Section C, prior to plant shutdown, NRC regulations limit access to the DCPP NDT to $37.2 million. Given the significant savings to customers of performing decommissioning planning activities over the next six years rather than waiting to initiate these activities until after shutdown, PG&E requests the Commission to authorize recovery of these costs from customers directly in retail rates via the ND NBC.

PG&E's revenue requirement and ratemaking proposal for these decommissioning planning costs is presented in Chapter 11.

C. NRC Regulations Limit Access to the DCPP NDT Pre-Shutdown

To prepare for eventual decommissioning of a nuclear power plant, the NRC requires the licensee/operator to ensure that funds will be available to decommission the facility. In California, this funding assurance is provided through trusts funded by utility customers. Within two years of shutting down the plant, the licensee/operator must submit a Post-Shutdown Decommissioning Activities Report (PSDAR) to the NRC. At any time before shutdown and prior to submitting the PSDAR, the licensee/operator may access the NDT for up to 3 percent of the generic decommissioning formula funding amount. According to Title 10 of the Code of Federal Regulations (CFR) 50.82(a)(8)(ii), the 3 percent may be used only for "decommissioning planning."

Decommissioning planning is not defined in the regulation. But, according to the NRC, "planning" refers to "paper studies" as opposed to physical work at the site. Initially, the NRC permitted the use of planning funds for all issues related to decommissioning the facility, but the NRC Office of General Counsel more recently determined that the initial 3 percent withdrawal allowed for decommissioning planning is limited to paper studies related to radiological decommissioning. Paper studies include, for example, engineering designs, detailed decommissioning schedules and work plans, and License Amendment Requests (LAR). It does not include any physical removal, demolition, or disposal activities or any costs associated with maintaining or monitoring the site until decommissioning begins.

Additionally, the initial three percent can be used only to plan for radiological decommissioning; it cannot be used for spent fuel management planning, Independent Spent Fuel Storage Installation (ISFSI) decommissioning planning, or site restoration planning absent (1) a clear indication that monies in the fund were collected for those purposes and are clearly and consistently accounted for separately; or (2) an exemption from the NRC allowing use of co-mingled funds for those purposes.

The DCPP NDT includes estimated costs for: (1) decommissioning activities; (2) spent fuel management; (3) ISFSI decommissioning; and (4) non-radiological site restoration, but does not include subaccounts for each of these categories of costs. As such, the funds collected in the DCPP NDT have not been specifically earmarked for any purpose other than radiological decommissioning. Therefore, under current regulations, until plant shutdown, only $37.2 million is available to support decommissioning planning activities. Even after plant shutdown and submission of the PSDAR, funds can be withdrawn only for radiological decommissioning activities until all radiological decommissioning activities are completed (for DCPP, no sooner than 2035).

As authorized by 10 Code of Federal Regulations Part 50.12, PG&E is requesting that the NRC grant exemptions from the applicability of the regulations restricting access to the NDT for planning activities to allow PG&E to withdraw $187.8 million from the Diablo Canyon NDT to fund decommissioning planning activities necessary to support direct transition to decommissioning upon permanent cessation of operations. Additionally, PG&E is requesting the NRC to allow PG&E to use these funds to support planning for radiological decommissioning, spent fuel management, and site restoration activities

There is no time frame imposed on the NRC to reply to PG&E's request for exemptions. PG&E is requesting that the NRC respond to the exemption request by June 2019. Based on historic practice, PG&E does not expect the NRC to reply sooner than six months after submittal, and it may take 12 months or more for the NRC to reply to the exemption request. If the NRC grants the exemptions, PG&E will revise the cost recovery proposal for decommissioning planning costs presented in Chapter 11.

In the meantime, PG&E requests the Commission to find PG&E's cost estimate for decommissioning planning costs reasonable and authorize recovery of these costs directly from customers in retail rates through the ND NBC.

D. Summary of Costs

The purpose of the following sections is to present the activities needed to support decommissioning planning activities. Table 3-1 summarizes the decommissioning planning activities for 2019-2024 that will provide cost and scheduling efficiencies if performed prior to plant shut down. Cost line items in Table 3-1 include:

- Program Management, Oversight, and Fees. This category includes:
  - NRC fees for review and approval of each licensing submittal discussed in Section E.1.

- Federal, state, and local agency fees to conduct their review and approval of permits discussed in Section E.2.
- Future land use evaluations as discussed in Section E.2.
- Administrative costs associated with the Diablo Canyon Decommissioning Engagement Panel (DCDEP) as discussed in Section E.2.
- Site radiological characterization as discussed in Section E.3, which provides the basis for radiation protection, identification of contamination, assessment of potential risks, cost estimation, planning, and implementation of decommissioning.
- Planning/management, and project staff as discussed in Section E.4. Personnel functions include planning, licensing, permitting, project controls, management, engineering, health and safety, and maintenance and operations.

* Waste/Transportation/Material Management: Development of the Waste, Transportation, and the Material Management programs, as described in Section F.
* Power Block Modifications: Planning for security modifications, Spent Fuel Pool Island (SFPI), and Cold and Dark (C&D) Power, as described in Section G.
* Site Infrastructure: Plans and designs to relocate buildings to support demolition as soon as practical after final shutdown, as described in Section H.
* Reactor/Internals Segmentation: Complete an evaluation of the capability of the waste container system for storage of DCPP reactor vessel and internals segments prior to shutdown as described in Section I.
* Balance of Site Demolition: Preparing the site for demolition of buildings as soon as practicable after permanent shutdown, as discussed in Section J.

Sections E through J address the scopes of work that comprise the costs in Table 3-1 and include background information, an overview of the activities, lessons learned from industry benchmarking, and benefits from early planning.

TABLE 3-1
COST ESTIMATE SUMMARY
(THOUSANDS OF 2017 DOLLARS)

Line No.	Reasonableness Milestone	Pre-2018	2018	2019	2020	2021	2022	2023	2024	Total
1	Program Management, Oversight, and Fees	$7,368	$21,568	$15,961	$19,437	$21,793	$20,666	$20,563	$27,482	$154,837
2	Waste/ Transportation/ Material Management	–	–	–	–	–	–	–	892	892
3	Power Block Modifications	–	–	–	–	–	2,158	9,434	8,059	19,651
4	Site Infrastructure	–	–	565	2,402	3,225	105	4	694	6,995
5	Reactor/Internals Segmentation	–	–	–	–	1,350	–	–	–	1,350
6	Balance of Site Demolition	–	–	–	–	–	–	2,019	2,104	4,123
7	Grand Total	$7,368	$21,568	$16,526	$21,840	$26,368	$22,928	$32,020	$39,231	$187,848

E. Program Management, Oversight, and Fees

1. NRC Submittals

Even after permanent cessation of power operations, plants must continue to follow and comply with the licensing basis for the plant, including completion of all equipment surveillances and procedures required by the Technical Specifications (TS), and similar documents, to maintain the plant systems (e.g., structures, systems, and components (SSC) important to safety during normal operation) in an operational-ready state. However, because nuclear fuel is no longer in the reactors and the plant is no longer making power during decommissioning, most plant SSCs and associated surveillances and procedures will no longer be necessary after final plant shutdown. To eliminate the need to perform these unnecessary activities, plants must revise the licensing basis documents to reflect the permanently shut down status of the plant. Once the licensing basis documents are revised, the plant can reduce staffing and costs associated with complying with the operating license basis requirements.

The NRC must review and approve many of the licensing basis revisions.

Completing NRC licensing activities for decommissioning before plant shutdown will save time and money, a significant benefit to customers. Also, early approvals will allow implementation of the approved changes into plant documentation. Once conditions are met, PG&E can immediately execute the approved changes instead of taking several months or years to develop and issue documentation changes. Additionally, early approval provides certainty around scope of work and transition dates. While the scope of work associated with licensing changes can be estimated using industry precedent, early NRC approval will solidify a given work scope so that PG&E can continue to provide the best cost and schedule estimates for decommissioning.

The NRC is supportive of early document review and approval for decommissioning. In its recently issued Lessons Learned document, the NRC noted that:

> [L]icensees should be encouraged to begin planning for permanent reactor shutdown and decommissioning as early as reasonably practicable…this pre-planning will serve to provide for a smoother transition from reactor operation to decommissioning.

Moreover, PG&E relied on industry precedent to develop the list and scope of NRC submittals to submit early in support of an efficient transition to decommissioning after final shutdown. Benchmarking revealed that plants that did not submit requests early for NRC approval (e.g., such as those sites that unexpectedly shutdown) incurred day-for day delays in the startup of decommissioning activities, which increased costs by approximately $1 million/month.

In addition to its review of individual licensee information, PG&E reviewed summary documents prepared by industry groups, including Electric Power Research Institute (EPRI) and Nuclear Energy Institute (NEI).

Guidance from EPRI indicates the following two lessons learned from the Kewaunee and Vermont Yankee sites.

Early Regulatory Submittals: Sites used an approach to facilitate early submittal of several regulatory documents. This strategy was expected to help reduce the duration of the transition period and reduce costs. Regulatory submittals that required NRC approvals drove most of the early critical path decommissioning planning milestones. Further, early submittal of these documents helped minimize the delay to implementation of cost saving measures (e.g., implementation of reduced Emergency Plan (EP) requirements).

Early ISFSI Licensing: Delay of ISFSI licensing has a significant potential to greatly affect the length of the decommissioning and the decommissioning costs. Therefore, the design, licensing, and permitting of the ISFSI should be started as early as practical during the decommissioning transition process. Regulatory submittals that required NRC approvals drove most of the early critical path decommissioning planning milestones. Further, early submittal of these documents helped minimize the delay to implementation of cost saving measures (e.g., implementation of reduced EP requirements).

The remainder of this section identifies the NRC submittals and associated work scope that PG&E plans to prepare and submit in order to have NRC approvals in hand upon plant shutdown.

a. Post-Shutdown Decommissioning Activities Report with Site Specific DCE

Licensees must submit the PSDAR prior to or within two years following permanent cessation of operation. The PSDAR is a relatively brief document which describes the plant's planned decommissioning activities, including the following required items: (1) description of the planned major decommissioning activities, including which decommissioning method will be used (i.e., prompt decontamination and dismantlement, long-term storage (SAFSTOR), or a combination of the two); (2) schedule of the planned decommissioning activities, including the relationships between decommissioning activities; (3) DCE within five years prior to final shutdown in accordance with 10 CFR 50.75(f)(3), including costs associated with decommissioning activities, spent fuel management, and site restoration to demonstrate that sufficient funds are available to support license termination; and (4) an evaluation of environmental impacts associated with decommissioning the site and a determination of whether such impacts are bounded by appropriate previously-issued environmental review documents.

While the PSDAR does not require NRC approval, the NRC does review the PSDAR, and may send requests for additional information from the licensee.

The cost estimate includes preparation of an Environmental Impact Statement, PG&E licensing support to prepare the submittal, and NRC review.

b. Irradiated Fuel Management Plan

In accordance with 10 CFR 50.54(bb), within two years following permanent cessation of operation of the reactor or five years before expiration of the reactor operating license, whichever occurs first, the licensee must submit written notification to the NRC for its review and preliminary approval of its program by which the licensee intends to manage and provide funding for the management of all irradiated fuel at the reactor following permanent cessation of operation of the reactor until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository.

As stated, in part, in 10 CFR 50.54(bb):

> The licensee must demonstrate to the NRC that the elected actions will be consistent with NRC requirements for licensed possession of irradiated nuclear fuel and that the actions will be implemented on a timely basis.

For example, in its evaluation of the licensee's submittals for San Onofre Nuclear Generating Station (SONGS) Units 2 and 3, the NRC staff has relied on the selected methods of storage being consistent with those described in the Continued Storage of Spent Nuclear Fuel Rule (79 FR 56238) and NUREG-2157, "Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel," Volumes 1 and 2, dated September 2014. These actions must be implemented on a timely basis, and should be consistent with the expected timeframe of decommissioning within 60 years.

The cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

c. Expedited Spent Fuel Offload

In June 2017, the CPUC issued D.17-05-020, requiring PG&E to include in the site-specific decommissioning cost estimate presented in its 2018 NDCTP application:

> …an assessment for expediting dry cask loading. This assessment shall include both pre-shutdown and post shutdown options and costs for expediting dry cask loading.

PG&E conducted a preliminary evaluation demonstrating that it is technically feasible to expedite the fuel offload schedule to seven years after the DCPP Unit 2 shutdown date. This can be achieved by expediting post-shutdown offloading and using advanced dry cask storage systems. The seven-year offload schedule may be refined after PG&E completes a detailed analysis of DCPP-specific fuel data and potential process improvements. Additionally, the technology for dry cask storage is continuously improving and there is potential that shorter spent nuclear fuel cooling times may be feasible for Diablo Canyon fuel.

PG&E plans to identify any potential improvements in cooling time duration through a request for proposal process to select a dry cask storage system vendor. In the 2019-2024 timeframe, PG&E will work with the chosen dry cask storage vendor to perform all the work necessary to implement the chosen expedited spent fuel offload strategy at the DC ISFSI. This will include: (1) Completion of design and engineering analyses; (2) preparation of licensing documentation for submittal to the NRC; (3) NRC review and approval in accordance with 10 CFR 72.48 and 72.56; and (4) additional cost for the chosen dry cask storage system as compared to the existing dry cask storage system.

d. Greater-Than-Class-C Waste License Amendment Request

As part of dismantlement activities, waste generated from the reactor pressure vessel internals and appurtenances is classified as Greater-Than-Class-C (GTCC) waste. GTCC waste cannot be shipped off-site like lower class wastes, but must be stored in a long-term repository, similar to spent fuel. As part of the Expedited Spent Fuel Offload strategy, PG&E will determine what type of dry cask storage system will be used to store GTCC waste at the DC ISFSI until it is transferred to an approved, off-site facility. A LAR is required for the existing 10 CFR 72 site-specific ISFSI license to allow for storage of the GTCC waste at the DC ISFSI.

The cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

e. Permanently Defueled Technical Specifications (PDTS), Bases and Revised License Conditions License Amendment Request

Power reactor licensee TS specify modes of applicability that correspond to conditions of operation for the reactor or apply only when fuel is in the reactor vessel. For a permanently shutdown and defueled reactor, these modes refer to conditions that are no longer possible because the reactor cannot be operated and fuel cannot be placed in the reactor vessel. In such cases, TS with modes of applicability can be removed from the license without affecting the safety of the facility.

In addition, substantial changes can be made to the Administrative Controls section of the TS, including changes to facility staff responsibilities, staffing organization, and staffing levels. Some program and reporting requirements that only apply to operating reactors can also be deleted or modified. All licensees of recently permanently shutdown reactors have proposed comprehensive amendments to their facilities' TS to reflect their permanently shutdown and defueled status through the LAR process. This process to revise the TS involves identification of the accidents that are still relevant in the permanently defueled state, reclassifications of SSCs that are no longer important for safety, revisions to plant procedures, and revisions to the TS themselves. The PDTS LAR also typically includes changes to license conditions that are no longer applicable during decommissioning, such as mitigation of beyond-design-basis events), and the addition of aging management of SSCs in use for more than 40 years to support Spent Fuel Pools(SFP) operation.

The cost estimate includes PG&E licensing support to prepare the proposed revised TS, supporting documentation, and associated LAR, NRC review of the LAR, and implementation of the approved changes into plant procedures and other documentation.

f. Defueled Safety Analysis Report

The Final Safety Analysis Report (FSAR) documents the NRC-approved analyses and operations of DCPP. Upon DCPP permanent shutdown, the FSAR transitions to a Defueled Safety

Analysis Report (DSAR) to reflect the systems, operations, and analyses that will be in-place for decommissioning.

Changes are implemented into the DSAR upon permanent shutdown using the process defined in 10 CFR 50.59. This process includes obtaining NRC approval through LARs, as needed, such as the TS LARs, Certified Fuel Handler Training and Retraining, and the Regulatory Guide Commitments LAR. While the DSAR is not submitted prior to permanent shutdown because approvals are obtained through other LARs, to support development of the LARs and NRC review, changes to the FSAR need to be identified concurrent with LAR development.

This cost estimate includes the scope of work to develop a detailed mark-up of the FSAR that would be used for eventual implementation into the DSAR upon permanent shutdown. Following permanent shutdown, the DSAR would be submitted to the NRC every 24 months as required by 10 CFR 50.71(e)(4).

g. Certified Fuel Handler Training and Retraining Program

The NRC does not require licensed operators at decommissioning reactors. When licensees permanently shut down their reactors, they must continue to meet the minimum staffing requirements in the TS and required programs (e.g., emergency response organizations, fire brigade, and security). Given the reduced risk of a radiological incident once the certifications of permanent cessation of operation and permanent removal of fuel from the reactor vessel have been submitted, licensees typically transition their operating staff to a decommissioning organization. This transition includes replacing licensed senior operators with certified fuel handlers (CFH) as the on-shift management representatives responsible for supervising and directing the monitoring, storage, handling, and cooling of irradiated nuclear fuel in a manner consistent with ensuring public health and safety. The NRC currently requires that CFH be qualified with a training program that is approved by the NRC; however, the Decommissioning Rulemaking[2] proposes regulation changes that would allow licensees to implement training programs using approved licensing precedent. Therefore, decommissioning plants must develop their own CFH training program, but do not need to apply for approval of that program.

This cost estimate includes PG&E licensing support to prepare the CFH training program and implement the program into plant procedures and training documentation.

h. Post-Shutdown Emergency Plan Documents

The risk of an offsite radiological release is significantly lower, and the types of possible accidents are significantly fewer, at a nuclear power reactor that has permanently ceased operations and removed fuel from the reactor vessel than at an operating power reactor. During the decommissioning transition period, licensees typically request several EP licensing actions (i.e., LARs and exemption requests) to address the reduced risk associated with a permanently shut down and defueled facility. As discussed in the NRC's Regulatory Basis Document for the ongoing decommissioning rulemaking, the revised rulemaking will provide a graded approach to EP. This revision to the CFR provides a regulatory process for licensees to make changes to their EP to comply with the EP requirements corresponding to the level of decommissioning while minimizing the need for licensees to request license amendments. The regulations would define the graded approach to EP in four stages/phases:

- Post-Shutdown: permanent cessation of operations and removal of all fuel from the reactor vessel;
- Permanently Defueled: sufficient decay of the spent fuel in the SFPs such that it would not reach ignition temperature within 10 hours under adiabatic heat up conditions;

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[2] In 2014, in response to lessons learned from utilities that had undergone decommissioning, the NRC identified several decommissioning-related potential changes to regulations and the need for development of enhanced guidance. The final revised regulations are scheduled to be issued in 2019 and become effective in 2020. See Docket No. NRC-2015-0070, "Regulatory Improvements for Power Reactors Transitioning to Decommissioning."

- ISFSI-Only: transfer of all fuel to dry storage; and
- Removal of all spent fuel from the site.

Because the NRC is in the process of enhancing the regulatory process for implementing changes to EP requirements during each phase of decommissioning, PG&E does not anticipate having to submit an LAR or exemption request for EP-related changes. Instead, PG&E is assuming that documents may potentially be required to be provided to the NRC to demonstrate compliance with transition to the next NRC-defined phase of decommissioning. This cost estimate includes PG&E licensing support to prepare a submittal, NRC review, and implementation of the approved changes into plant documentation and procedures.

i. Permanently Defueled Emergency Plan Documents

Similar to the scope of work discussed for Item h, to support EP-related changes for a permanently defueled condition (i.e., spent fuel is being stored in the SFPs and had sufficient decay such that it would not reach ignition temperature within 10 hours under adiabatic heat up conditions), this cost estimate includes PG&E licensing support to prepare the NRC submittal, NRC review, and implementation of the approved changes into plant documentation and procedures. PG&E is assuming that documents may potentially be required to be provided to the NRC to demonstrate compliance with transition to the next NRC-defined phase of decommissioning discussed in the decommissioning rulemaking.

j. Permanently Defueled Security Plan License Amendment Request

The physical security requirements of 10 CFR 73.55, “Requirements for Physical Protection of Licensed Activities in Nuclear Power Reactors against Radiological Sabotage,” Appendix B, “General Criteria for Security Personnel,” and Appendix C, “Licensee Safeguards Contingency Plans,” to 10 CFR Part 73, “Physical Protection of Plants and Materials,” continue to apply to a nuclear power reactor after permanent cessation of operations and removal of fuel from the reactor vessel. Currently, there are no explicit regulatory provisions distinguishing physical security requirements for a power reactor that has been shut down from those for an operating power reactor. These security requirements are designed to protect against the design-basis threat of radiological sabotage.

Licensees have sought and obtained NRC approval of exemptions to reduce physical security requirements for permanently shut down reactors because the security-risk profile presented by a decommissioning plant is much less than when it was operating. The physical security-related exemptions that were requested by the recent licensees (such as Kewaunee, SONGS, CR, and Vermont Yankee) to transition to decommissioning include areas such as severe weather and emergency authority of CFHs, communications between the central alarm station and control room, number of armed responders, requirements for force-on-force exercises, and a combination of the central and secondary alarm stations.

As discussed in the NRC's Regulatory Basis Document for the ongoing decommissioning rulemaking, the revised rulemaking will standardize several aspects of physical security, such as defining vital areas and target sets. Thus, many of the physical security program changes at decommissioning reactor sites can be accomplished without NRC approval provided the licensees demonstrate no reduction in the effectiveness of the physical security program. However, experience has shown that, although the physical security program changes may not require NRC approval, exemption, or a license amendment, significant NRC staff effort will be expended in the review and verification that the security plan remains effective.

This cost estimate includes PG&E licensing support to prepare the submittal, NRC review, and implementation of the approved changes into plant documentation and procedures.

k. ISFSI-Only Technical Specifications, Bases, and Revised License Conditions LAR

To support transition to a site undergoing decommissioning with spent nuclear fuel only at the ISFSI (i.e., all spent nuclear fuel has been moved from the SFPs to the ISFSI), changes will be made to the ISFSI

TS. This cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

l. ISFSI-Only Emergency Plan Documents

To support transition to a site undergoing decommissioning with spent nuclear fuel only at the ISFSI (i.e., all spent nuclear fuel has been moved from the SFPs to the ISFSI), changes will be made to the site EP.

This cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

m. ISFSI-Only Security Plan License Amendment Request

To support transition to a site undergoing decommissioning with spent nuclear fuel only at the ISFSI (i.e., all spent nuclear fuel has been moved from the SFPs to the ISFSI), changes will be made to the physical security program commensurate with the risk as discussed in the decommissioning rulemaking. This cost estimate includes PG&E licensing support to prepare the submittal and NRC review of an ISFSI-only physical security program.

n. Changes to Offsite Dose Calculation Manual

The Offsite Dose Calculation Manual (ODCM) provides the methodology and parameters for determining the current operational offsite doses for DCPP, describes the radioactive effluent controls and radiological environmental monitoring activities, and describes the information that should be included in routine radiological reports to the NRC. To reflect the changes to the plant during decommissioning, the ODCM requires revision and submittal to the NRC.

This cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

o. Decommissioned Quality Assurance Program Approval

The Quality Assurance (QA) Program is currently implemented at DCPP to provide assurance that the design, construction, and operation of DCPP and the ISFSI are in conformance with applicable regulatory requirements and with the specified design bases. Before beginning major decommissioning activities, the QA Program plan is updated to reflect the permanently shutdown and defueled condition. In general, this plan is updated to remove commitments to industry standards and RGs that do not apply to a permanently defueled plant and to make new commitments to other industry standards and guides that are appropriate for decommissioning and ISFSI operations. Further, the QA Program plan is typically modified to so that the document is applicable throughout the decommissioning, despite the significant changes in the scope of activities performed and the responsibilities of personnel over the course of the decommissioning.

Because the types of QA Program plan updates require NRC approval, this cost estimate includes PG&E licensing support to prepare the submittal, NRC review, and implementation of the approved changes into plant procedures.

p. Regulatory Guide Commitments LAR

To support decommissioning, SONGS submitted an LAR[3] and obtained NRC approval[4] to revise the RGs that were committed to in the FSAR. As discussed in Item f above, the FSAR revisions will be drafted during preparation of other licensing submittals. Consistent with SONGS precedent, it is assumed that a similar RG commitments LAR will be needed to facilitate implementation of FSAR changes, such as transitioning to a SFP island (see Section G).

This cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

q. Annual Fee Reclassification LAR

10 CFR 171.15 mandates an annual fee for nuclear power plants and ISFSIs based on the operating status (i.e., power operations, decommissioning, etc.). The annual fee may be reclassified and significantly reduced for decommissioning power plants. Other decommissioning plants, such as Kewaunee and Vermont Yankee, have applied for and received an annual fee reclassification via an LAR.

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3 ADAMS Accession No. ML15236A018.

4 ADAMS Accession No. ML16055A522.

This cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

r. Certifications for Permanent Fuel Removal

In accordance with 10 CFR 50.82(a)(ii), after the reactor vessel has been defueled, a certification of permanent fuel removal will be submitted to the NRC under oath and affirmation. The content of the letter will specify the actual date of permanent unit shutdown, the date that fuel was removed from the reactor vessel, and the current location of the fuel. After the NRC dockets both certifications, the plant is no longer authorized to operate the reactor or have fuel in the reactor vessel.

PG&E will submit the Certification for Unit 1 Permanent Fuel Removal in 2024. This cost estimate includes PG&E licensing support to prepare the submittal and NRC review.

2. Permits, Future Land Use, and Stakeholder Engagement

Federal, state, and local permits and approvals are required to perform nearly every decommissioning activity. Through these processes, the decommissioning project will be subject to thorough environmental review as required by both the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA). In addition to the permits subject to NEPA and CEQA review, the project will require numerous individual permits from state and local agencies.

Permitting is a critical path item. If activities to support permitting are not initiated and completed sufficiently in advance of plant shutdown, all activities will be delayed awaiting receipt of permits. PG&E's goal is to have the major permits necessary to begin physical decommissioning activities in hand as of plant shut down. Benchmarking California sites, as well as PG&E's own experience obtaining Coastal Development Permits (CDP), coastal use permits, California State Lands Commission (CSLC) lease amendments, and other permits supports initiating these required processes as soon as possible. Each step along the way takes time: preparing the applications, responding to agency data requests, supporting the agencies' environmental review processes, commenting on agency documents, including Environmental Impact Reports (EIR) and staff reports, participating in hearings, and submitting and/or defending appeals of the permit. A complete list of environmental permits required for decommissioning is included as DCE Table 3-2.

The decommissioning activities PG&E expects will require permits include, but are not limited to:

- C&D activities including construction of new 12 kilovolt (kV) infrastructure;
- SFP island construction;
- ISFSI pad modifications to store GTCC waste;
- Demolition of buildings and infrastructure including containment buildings, turbine building, 230 kV, etc.;
- Grading for structure demolition and restoration;
- Offsite transport of hazardous, non-hazardous, and radiological waste;
- Water management and treatment; and
- Operation of heavy equipment used for demolition purposes.

As with NRC licensing activities, early permitting activities for decommissioning will save time and money, a significant benefit to customers. Also, early approval allows for a known scope of work and execution schedule so that detailed project planning can begin as soon as possible after plant shut down.

PG&E benchmarked five California-based decommissioning sites with similar permitting characteristics to DCPP to assist in determining the state and local permits required for DCPP decommissioning and to supplement its own experiences with state permitting processes to determine the time to obtain the permits:

- SONGS Unit 2 and Unit 3 Decommissioning;
- Humboldt Bay Power Plant Unit 3 Decommissioning;
- Dynegy South Bay Power Plant Decommissioning and Demolition;
- NRG Carlsbad Power Plant Modernization/Reconstruction; and
- Los Angeles Telecommunications Hub

As noted above, benchmarking demonstrated that permitting activities should begin as early as possible with clear communications between involved agencies. At SONGS, because final plant shutdown was unexpected, early permitting activities could not be performed to support decommissioning. As a result, decommissioning activities have been delayed, causing increased and unexpected costs. PG&E understands that as of November 2018, SONGS is still awaiting approval of permits required to initiate major decommissioning activities even though SONGS was shutdown in 2012. At the Los Angeles Telecommunications Hub and Dynegy South Bay Power Plant, delays and increased costs resulted from the number of review agencies involved in those processes.

The remainder of this section identifies the permits PG&E expects to require for decommissioning and the scope of work associated with obtaining these permits before plant shutdown.

a. Major Discretionary Permits Required for Decommissioning Activities

Most major discretionary permits require a voting body to exercise judgment or deliberate to approve or deny issuance of a permit at their discretion. These permits can be subject to additional special conditions as determined by the voting body. Major discretionary permits required to support decommissioning activities include CDP(s), CSLC lease or lease amendment, and/or other CSLC actions needed for any proposed repurposing of buildings or lands.

All of the industrial areas of DCPP and a majority of the proposed decommissioning activities are located within the California coastal zone. In addition to a new CDP for decommissioning activities, PG&E must obtain an amendment to the CDP for the DC ISFSI in order implement its proposal to store GTCC waste at the existing DC ISFSI.

The CSLC issued PG&E Lease PRC 9347.1 in August 2016 for the continued use of the breakwaters, Intake Structure, and Discharge Structure (and other ancillary structures).[5] The lease expires in August 2025. Special Provision 5.iii states PG&E shall submit "no later than August 26, 2020, a proposed plan for the restoration of the Lease Premises together with a timeline for obtaining all necessary permits and conducting the work prior to the expiration of this Lease." In other

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5 CSLC Lease PRC 9347.1, dated August 8, 2016.

words, PG&E will need a new lease from the CSLC to proceed with decommissioning activities.

This cost estimate includes the costs of licensing and environmental permitting support to develop environmental evaluations, prepare the permitting submittals to the California Coastal Commission (CCC) and San Luis Obispo County, consultants to support document preparation and agency reviews, the associated CCC and SLO County review fees, and agency preparation of an EIR. It also includes PG&E licensing and environmental permitting support to develop the long-term plans for the breakwaters, intake, and discharge structures, prepare the submittal, and participate in the CSLC review for the new lease. This cost estimate does not include the cost of mitigation measures that agencies may require as conditions to approval of permits.

b. Environmental Permits

Environmental permits are resource-based permits issued by federal, state, or local agencies that typically are not subject to discretionary actions (e.g., U.S. Army Corp of Engineers, California Department of Fish and Wildlife, Central Coast Regional Water Quality Control Board). PG&E anticipates that several environmental permits will be needed to support work activities immediately after final DCPP shutdown, including, but not limited to water discharge permits and air emissions permits.

This cost estimate includes PG&E permitting and environmental support to obtain necessary environmental permits.

c. Ministerial Permits

Ministerial permits are permits that involve little or no personal judgment by public officials as to the wisdom or manner of carrying out the work. They involve only the use of fixed standards or objective measurements to determine compliance. Public officials apply laws to the facts as presented but use no special discretion or judgement in reaching a decision (e.g., county of SLO demolition permits, building permits, transportation permits). PG&E anticipates that several ministerial permits will be needed to support work activities immediately after final DCPP shutdown, including, but not limited to demolition, grading, and building permits from SLO County Planning and Building Department. These permits will support implementation of the C&D strategy (i.e., construction of new 12 kV infrastructure), site security modifications, and infrastructure for waste processing and management facilities.

This cost estimate includes PG&E permitting and environmental support to obtain necessary ministerial permits.

d. Future Land Use

During decommissioning planning, PG&E will develop a Future Land Use Plan for the DCPP site that will represent the culmination of PG&E's external community and agency outreach, as well as internal decision-making processes to arrive at a proposed during- and post-decommissioning land use plan. This plan will evaluate options for future uses of the site and provide PG&E's preferred alternative, including facilities to be retained, reused, repurposed, and removed.

To evaluate the potential options, PG&E must evaluate environmental resources, socioeconomic factors, engineering (such as infrastructure needed to support the potential site use), and cost factors related to final land uses at the site. This future land use plan will inform the permitting process, as it can be used in the preparation of land use applications and as a resource document for the CEQA process.

This cost estimate includes PG&E permitting and environmental support to develop the Future Land Use Plan and consultants to support potential land use option evaluations.

e. Diablo Canyon Decommissioning Engagement Panel

Decommissioning will be a long and complex process requiring the balancing of many interests. PG&E has convened an external stakeholder group—the DCDEP—to support open and transparent dialogue with the community on decommissioning matters. The panel is a volunteer-based, non-regulatory body, the purpose of which is to enhance and foster open communication, public involvement, and education on decommissioning plans and activities, including spent fuel management, EP, security, future potential land uses and repurposing, and the environmental review process for decommissioning. PG&E plans to hold DCDEP meetings on a monthly basis until submittal of the 2018 NDCTP and quarterly (or as needed) thereafter.

As noted above, the panel members are volunteers and are not paid by PG&E or compensated for their time. Accordingly, this cost estimate includes administrative-type costs only, including fees for meeting spaces, meeting supplies and logistics, a meeting facilitator, and costs of personnel to support the DCDEP.

3. Site Characterization

Radiological characterization provides the basis for radiation protection, identification of contamination, assessment of potential risks, cost estimation, planning and implementation of decommissioning, and other matters. This cost estimate includes costs for the completion of the Historical Site Assessment, writing of the procedures in support of all Final Site Survey (FSS) processes (including sampling, surveying, count room protocols, and data processes), work with demolition planning to ensure FSS work is minimally impacted by demolition activities, and purchase of required FSS equipment.

4. Planning/Management/Project Staff

Benchmarking has been completed with numerous plants that are undergoing or have completed decommissioning. In addition to benchmarking specific topics or facets of decommissioning activities, particular attention has been paid to decommissioning planning. Lessons learned from individual plants, groups representing the nuclear industry (NEI and EPRI), and the NRC have indicated pre-work and planning are key to ensuring a smooth and efficient transition from an operating status to decommissioning. Early, detailed preparation reduces the duration and cost of ND while enhancing safety and efficiency. For example:

Oyster Creek: Decommissioning planning should start well before final plant shutdown. With a decommissioning plan in place prior to shutdown, there are opportunities for considerable savings to the overall cost of decommissioning.

Connecticut Yankee: Many of the planning activities for the decommissioning of a plant can be conducted well in advance of the actual permanent shutdown. The high-level strategy for the decommissioning should begin when the possibility of decommissioning is being considered.

Once the 2018 NDCTP is approved, the DCPP Decommissioning organization will begin planning the associated work in preparation for permanent cessation of operations. PG&E plans to begin a transition several months prior to Unit 1 shutdown that will include preparing the staff and the plant for changes needed to support the cessation of power generation at the units. The transition may take 18-24 months.

Decommissioning Project Staff work activities include the following:

- Development of future NDCTP submittals (including revisions to the DCE), efforts associated with discovery, responses, hearings.
- Decommissioning pre-planning including:
  - Developing more detailed decommissioning strategies and work execution approaches; and
  - Integration of the additional activities with other decommissioning planning efforts to support the development of a more comprehensive, and well-defined decommissioning strategy and greater efficiencies in work execution.
- Executable work planning. Validating plans once external inputs are received.
- Program development and changes to existing programs (e.g., engineering and RP programs).
- Procedure updates/development to support new programs for a decommissioned site.
- Development/revision to existing work processes and detailed work package development.
- Oversight to contractors developing specific approved scope of work.
- Oversight and project management of scopes of work discussed previously.
- Worker training (new roles and new procedures).
- Contract support for scopes of work to start early in decommissioning.

- Specialty contracts to prepare to execute Historical Site Assessment surveys prior to shutdown.
- Planning, engineering for early removal of Tcom/Medical building (#102) to increase efficiencies for decommissioning by eliminating traffic/congestion issues between it and the Unit 1 buttress and increasing laydown areas which will be required for decommissioning, and to support more efficient security personnel use.
- Administrative costs associated with the decommissioning planning staff.
- Overall ramp-up of staff in later years to support decommissioning implementation.

F. Waste/Transportation/Material Management

The Waste, Transportation, and the Material Management programs are integral to successful implementation of key decommissioning activities. In order for these programs to be ready for the start of decommissioning, program development prior to shutdown, including procedure writing, mobilization, and planning activities must occur.

G. Power Block Modifications

PG&E's DCE includes three projects scheduled immediately after plant shutdown, each of which supports safe, efficient, cost-effective implementation of the remaining decommissioning activities: security modifications, SFPI, and C&D power. To ensure immediate implementation of these projects upon plant shut down, PG&E proposes to complete necessary design changes (including revisions to calculations and drawings), planning, licensing, and/or sourcing in advance of plant shut down.

Completing the preliminary work necessary to implement security modifications, SFPI, and C&D power immediately upon plant shutdown will save time and money and support safe, efficient decommissioning activities throughout the project. Early planning and NRC approval is particularly important for the planned security modifications because the cost savings associated with the modifications begin as soon as they are installed, earlier installation will result in greater net savings.

For security modifications, SFPI and C&D power, having NRC approvals in hand allows PG&E to implement approved changes into plant documentation and design packages prior to plant shutdown. That means PG&E can immediately execute the approved changes upon plant shut down, rather than initiating the process after plant shut down and taking several months or a year to develop and issue documentation changes. Additionally, developing the installation work packages prior to final shutdown allows for timely installation of these early projects, allowing the decommissioning project to move forward on schedule.

This cost estimate includes the costs of the activities described below. They include only the costs to ensure physical installation can occur immediately upon plant shutdown, not the costs of physical installation. Physical installation will occur after plant shutdown.

1. Security Modifications

There are significant changes at a site during decommissioning activities. Security plans and staffing can be adjusted to reflect the site changes. Implementing security modifications improves efficiency and, ultimately, allows security staff reductions while still maintaining a robust decommissioning defense strategy.

To prepare for physical installation of these proposed security modifications, PG&E must develop and submit design changes to the NRC for approval. While the NRC considers these design changes, PG&E will issue a request for proposals to select the contractor to install the modifications. The contractor and PG&E will develop, review, and issue detailed work instructions, diagrams, and documentation to support necessary installation, testing, operation, and maintenance of the planned security modifications consistent with work planning procedures.

2. Spent Fuel Pool Island

Several existing plant systems are used to ensure there is adequate cooling of the spent fuel pools. These existing systems could continue to be used for SFP cooling during decommissioning; however, to facilitate safe and efficient decommissioning, the nuclear industry has implemented the SFPI concept. A SFPI is an independent cooling system for the SFPs that allows the licensee to abandon the in-place plant systems supporting SFP cooling. PG&E plans to develop and install an SFPI to reduce the risk of decommissioning activities impacting the SFPs.

To prepare for physical installation of the SFPI, PG&E must develop and submit an engineering design (including revisions to calculations and drawings) to the NRC. While the NRC considers these design changes, PG&E will issue a request for proposals to select the contract to install the SFPI after shutdown. PG&E and the chosen contractor will develop, review, and issue detailed work instructions, diagrams, and documentation to support necessary installation, testing, operation, and maintenance of the planned SFPI in accordance with the existing work planning procedures.

3. Cold and Dark

Perhaps the most significant safety hazard associated with decommissioning power plants is the risk posed by personnel and equipment coming in direct contact with exposed and energized electrical circuits. Industry operating experience indicates that even a robust electrical clearance program is insufficient at managing risks associated with electrical shock or arc flash events, in power plants being decommissioned and demolished. The most effective approach to manage these risks is to remove or disconnect the original power supplies from structures and components within structures before undergoing demolition. This necessitates the installation of an alternate external power supply to support decommissioning work and for selected power plant loads and lighting. This alternate power supply, referred to as C&D power, is independent of the normal plant power supply and distribution system. PG&E intends to install C&D power to reduce the risk of decommissioning activities.

To prepare for physical installation of C&D power, PG&E must develop and submit an engineering design (including revisions to calculations and drawings) to the NRC. While the NRC considers these design changes, PG&E will issue a request for proposals to select the contract to install C&D power after plant shut down. PG&E and the chosen contractor will develop, review, and issue detailed work instructions, diagrams, and documentation to support necessary installation, testing, operation, and maintenance of the planned SFPI in accordance with the existing work planning procedures. To ensure that materials are on-site for installation, long lead-time items will be purchased prior to final plant shut down.

H. Site Infrastructure

Site Infrastructure work activities includes development of plans and design to relocate the telecommunications equipment in Building 102 to enable early demolition of this building which supports more efficient security personnel use and greater space efficiency for key decommissioning activities.

I. Reactor/Internals Segmentation

In addition to the general project staff activities noted above, the decommissioning team will need to perform (or contract) technical evaluations prior to decommissioning to support implementation of strategies, respond to NRC or permitting agency requests for additional information, and other activities supporting decommissioning work. As an example, a technical evaluation must be performed to confirm that the Holtec packaging system and waste transportation cask will accommodate the radioactivity quantities and heat loads that will be present in the RPV and internals. This evaluation must be completed long before planned segmentation given the significant lead time for design, fabrication, and delivery of the waste packages and transportation casks.

The cost estimate for this analysis includes PG&E and contractor labor costs, technical evaluations, planning and procurement activities, not already included elsewhere in this application.

J. Balance of Site Demolition

Early completion of preparation work will support demolition of site buildings as soon as practical after final shutdown. Detailed engineering and planning is needed for each structure to ensure that it is demolished in a safe, timely, and cost-effective manner. In addition, early mobilization of personnel and equipment also will be completed prior to shutdown to gain efficiencies.

K. Conclusion

The Commission should adopt PGE’s proposed early decommissioning planning activities and associated costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

DIABLO CANYON POWER PLANT SITE-SPECIFIC

DECOMMISSIONING COST ESTIMATE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
DIABLO CANYON POWER PLANT SITE-SPECIFIC DECOMMISSIONING COST ESTIMATE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
DIABLO CANYON POWER PLANT SITE-SPECIFIC DECOMMISSIONING COST ESTIMATE

A. Introduction

The purpose of this chapter is to present the results of Pacific Gas and Electric Company's (PG&E) Diablo Canyon Power Plant (DCPP) Units 1 and 2 site-specific decommissioning cost estimate (DCE). The DCE identifies the cost and schedule to conduct radiological decommissioning of DCPP; termination of the DCPP 10 Code of Federal Regulations (CFR) Part 50 licenses; spent fuel management until the Spent Nuclear Fuel (SNF) and Greater Than Class C (GTCC) waste have been removed to an off-site facility; termination of the Diablo Canyon Independent Spent Fuel Storage Installation (DC ISFSI) 10 CFR Part 72 license; and site restoration activities.

The DCE provided as PG&E Prepared Testimony, Chapter 4, Attachment A includes a comprehensive explanation of PG&E's derivation of the costs of decommissioning DCPP.

B. Summary

As described in PG&E Prepared Testimony, Chapter 2, the DCE was developed from the ground up without reference to the unit cost factor methodology used for purposes of financial planning in prior Nuclear Decommissioning Cost Triennial Proceedings (NDCTP).

The projected total cost to decommission DCPP, including costs spent to date, is $4.8 billion (nominal/2017 $) as shown in Table 4-1.

TABLE 4-1
PROJECTED TOTAL COST TO DECOMMISSION DCPP
(THOUSANDS OF DOLLARS)

ID	Scope Description	Total
1	Program Management, Oversight, & Fees	$1,462,045
2	Security Operations	560,686
3	Waste/Transportation/Material Management (Excluding: Breakwater, Reactor Vessel/Internal Segmentation, & Large Component Removal)	855,211
4	Power Block Modifications	80,707
5	Site Infrastructure	140,972
6	Large Component Removal	166,370
7	Reactor/Internals Segmentation	332,341
8	Spent Fuel Transfer to ISFSI	235,541
9	Turbine Building	68,667
10	Aux Building	92,122
11	Containment	121,012
12	Fuel Handling Building	48,627
14	Balance of Site	80,702
15	Intake	41,654
16	Discharge	15,122
17	Breakwater	286,326
18	Non-ISFSI Site Restoration	135,075
19	Spent Fuel Transfer to United States (U.S.) Department of Energy (DOE)	24,258
20	ISFSI Demolition and Site Restoration	54,956
21	Grand Total	$4,802,395

As explained in PG&E Prepared Testimony, Chapters 3 and 11, PG&E is proposing to perform decommissioning planning during the next six years, and to adopt a separate revenue mechanism for recovery of these planning costs. While included in Table 4-1, these costs are not included for purposes of determining the amount of trust contributions and revenue requirements contained in Chapter 10 and 11.

C. Organization of the DCE

Because DCPP decommissioning is a large, complex project that will span decades, PG&E organized its cost estimate using a standard project management methodology consisting of a work breakdown structure that details scopes of work required, time tables, and cost estimates. PG&E divided the DCE into three Nuclear Regulatory Commission (NRC)-defined cost categories (or phases):

License Termination: Costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (10 CFR 50.75). The costs included in this category are generally sufficient to terminate the plant's operating licenses, recognizing that spent fuel management represents an additional cost liability that will interact with the license termination effort. License Termination cost estimates are described in DCE Section 4.1.1.

Spent Fuel Management: Costs associated with the containerization and transfer of spent fuel from the Spent Fuel Pools (SFP) to the DC ISFSI and the transfer of casks from the DC ISFSI to an approved off-site location. Costs also are included for the operations of the SFPs and management of the DC ISFSI until all SNF and GTCC waste is transferred to an approved off-site location. Spent Fuel Management cost estimates are described in DCE Section 4.1.2.

Site Restoration: Costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from radiological contamination. This includes structures never exposed to radioactive materials (such as office buildings), as well as those facilities that have been decontaminated to appropriate levels (such as the turbine building). Structures are assumed to be removed to a depth of three feet (unless noted otherwise) and backfilled to conform to local grade. Site Restoration cost estimates are described in Section 4.1.3.

Table 4-2 provides a breakdown of the DCE by decommissioning phase and unit.

TABLE 4-2
PROJECTED TOTAL COST TO DECOMMISSION DCPP
BY DECOMMISSIONING PHASE AND UNIT
(THOUSANDS OF DOLLARS)

Line No.	Decommissioning Phase	Unit 1	Unit 2	Grand Total
1	License Termination	$1,465,834	$1,462,531	$2,928,365
2	Spent Fuel Management	600,752	571,839	1,172,592
3	Site Restoration	190,308	511,130	701,438
4	Grand Total	$2,256,894	$2,545,501	$4,802,395

Within each category, costs were estimated by scope of work. The costs assigned to these categories are allocations. Cost elements are designated to enable comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., asset retirement obligation determinations). In fact, there may be considerable interaction among the activities in the three subcategories. For example, an owner may decide to remove non-contaminated structures early in the project to improve access to contaminated facilities or plant components. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost.

D. Comparison to Prior NDCTP Estimates

In order to comply with the Commission's directive to provide a comparison with the two most recent NDCTP cost estimates, Table 4-3 allocates the 2012 and 2015 NDCTP cost estimates into the cost categories used in this NDCTP.

TABLE 4-3
COMPARISON OF 2012, 2015, AND 2018 NDCTP DCPP COST ESTIMATES
(THOUSANDS OF DOLLARS)

		2012 NDCTP		2015 NDCTP		2018 NDCTP
ID	Scope Description	As-Filed 2012 NDCTP (2017$)	Approved 2012 NDCTP (2017$)	As-Filed 2015 NDCTP (2017$)	Approved 2015 NDCTP (2017$)	Request 2018 NDCTP (2017$)
1	Program Management, Oversight, and Fees	$976,691	$866,017	$1,210,156	$836,038	$1,462,045
2	Security Operations	684,366	406,887	748,516	218,574	560,686
3	Waste/Transportation/Material Management (Excluding: Breakwater, Reactor Vessel/Internal Segmentation, & Large Component Removal)	286,847	244,821	371,944	314,761	855,211
4	Power Block Modifications	66,994	67,892	59,174	57,861	80,707
5	Site Infrastructure	11,365	11,518	19,158	11,534	140,972
6	Large Component Removal	162,727	125,380	181,640	178,861	166,370
7	Reactor/Internals Segmentation	181,766	126,442	276,862	190,933	332,341
8	Spent Fuel transfer to ISFSI	213,162	213,249	236,855	287,098	235,541
9	Turbine Building	28,103	28,480	28,141	28,737	68,667
10	Aux Building	63,214	64,062	67,171	64,669	92,122
11	Containment	204,418	192,258	198,340	193,228	121,012
12	Fuel Handling Building	27,201	27,566	24,008	23,632	48,627
14	Balance of Site	30,914	31,329	33,325	31,593	80,702
15	Intake Structure	10,354	10,493	10,504	10,523	41,654
16	Discharge Structure	1,460	1,480	1,495	1,483	15,122
17	Breakwater	72,818	73,794	376,809	74,019	286,326
18	Non-ISFSI Site Restoration	112,851	60,888	120,248	83,737	135,075
19	Spent Fuel transfer to DOE	128,645	130,370	107,309	104,928	24,258
20	ISFSI Demolition and Site Restoration	5,216	5,277	9,734	417	54,956
21	Grand Total	$3,269,112	$2,688,201	$4,081,388	$2,712,625	$4,802,395

As stated in Chapter 2, the current DCE is a ground-up study prepared as an executable decommissioning plan. It was not prepared with reference to the prior TLG cost studies and uses a completely different methodology than the prior unit cost factor methodology. In other words, the estimated costs were developed through entirely different processes, and differences between the estimates may not correlate to specific individual assumptions.

E. Major Components of DCE

This section provides additional information about significant decommissioning activities.[1]

1. Breakwater Facilities

The DCE includes the costs for the complete removal of the DCPP intake structure, breakwaters, and discharge structure. Removal of the DCPP breakwaters presents environmental challenges and represents a significant component of decommissioning costs, but, as described below, PG&E is contractually liable to remove these facilities by the terms of PG&E's California State Lands Commission (CSLC) lease. Therefore, breakwaters removal must be included in the cost of decommissioning DCPP. This section describes the DCPP breakwaters facilities and the costs of removal; possible alternatives to removal are discussed in PG&E Prepared Testimony, Chapter 5, Section D.

a. Description of Off-Shore Facilities

As part of its once-through cooling system, DCPP has structures (facilities) that are situated on tide and submerged lands in and adjacent to the Pacific Ocean. These are the Cooling Water Intake Structure, Breakwaters, and the Cooling Water Discharge Structure (see Figures 4-1 and 4-2). The DCPP circulating water system draws water from the Pacific Ocean via the cooling water intake structure. Breakwaters extend from two points into the ocean, creating an area of calm surface water around the intake structure. The breakwaters are built from man-made interlocking concrete tri-bar, (concrete block in a

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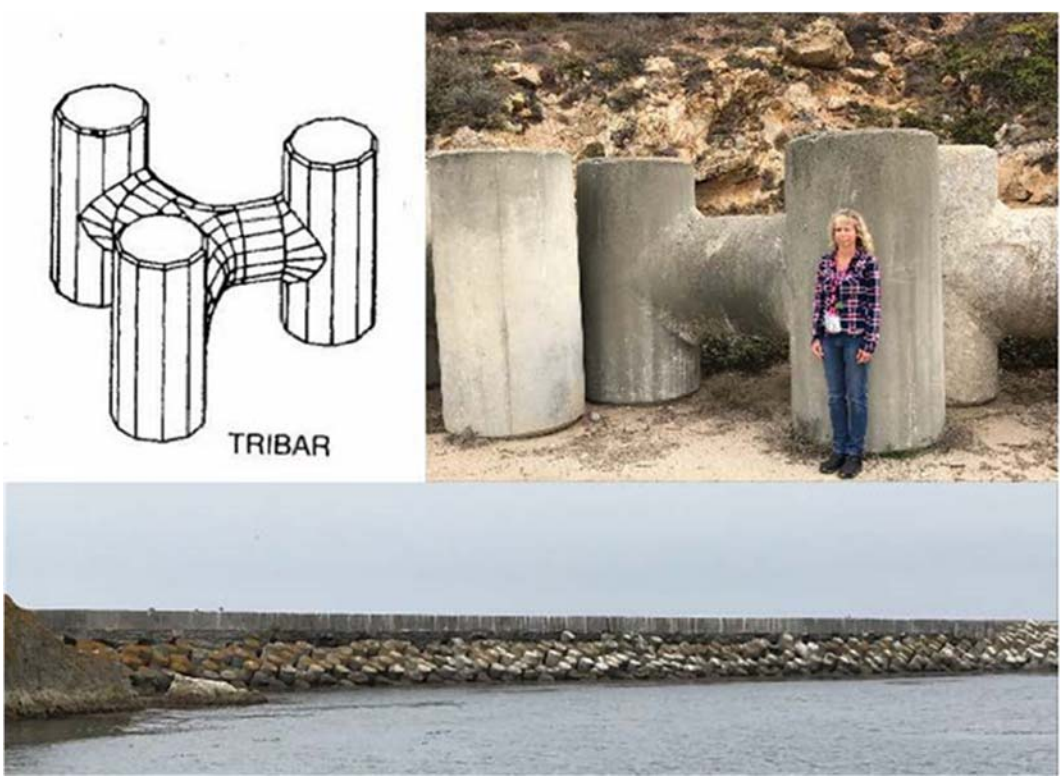
[1] SNF issues are discussed in PG&E Prepared Testimony, Chapter 6.

complex geometric shape weighing up to 38 tons, used to protect harbor walls from the erosive force of ocean waves) (see Figure 4-3).

FIGURE 4-1
DCPP'S INTAKE STRUCTURE, BREAKWATERS, AND DISCHARGE STRUCTURE LOOKING NORTH

FIGURE 4-2
DCPP'S INTAKE STRUCTURE, BREAKWATERS, AND DISCHARGE STRUCTURE LOOKING SOUTHEAST

FIGURE 4-3
CONCRETE TRIBAR



b. California State Land Commission Lease Requirements

Prior to construction of DCPP, PG&E obtained a 49-year lease and a 49-year right-of-way from the CSLC to construct, operate, and maintain the cooling water intake and discharge structures. See Table 4-4.

TABLE 4-4
PREVIOUS CSLC LEASE AND RIGHT-OF-WAY FOR DCPP

Line No.	Commencement	Lease Premise(s)	Lease	Original Expiration
1	August 28, 1969	Intake Structure & Intake Breakwaters	Lease No. PRC 4307.1 General Lease	August 27, 2018
2	June 1, 1970	Cooling Water Discharge Channel	Lease No. PRC 4449.1 Right of Way	May 31, 2019

Lease No. PRC 4307.1 Section 14 and Lease No. PRC 4449.1 Section 16 both required PG&E to restore the lease premises, as nearly as possible, to the conditions existing prior to the installation or construction of any improvements when the lease is terminated:

> That the following specifically enumerated and described structures, buildings, pipe lines, machinery and facilities placed or erected by Lessee or existing and located upon said demised premises shall become and remain the property of the State upon expiration or earlier termination of this agreement;…
>
> All other structures, buildings, pipe lines, machinery and facilities placed or erected by Lessee or existing and located upon said demised premises shall be salvaged and removed by Lessee, at Lessee's sole expense and risk, within ninety (90) days after the expiration of the period of this agreement or prior to any sooner termination of this agreement; and Lessee in so doing shall restore said demised premises as nearly as possible to the condition existing prior to the erection or placing of the structures, buildings, pipe lines, machinery and facilities so removed….

As a result of the decision to retire DCPP, PG&E and the CSLC agreed to replace the old general lease and right-of-way with one new lease that would expire at the same time as DCPP's NRC license for operation of Unit 2 (see Table 4-5). On June 28, 2016, the CSLC authorized termination of the old leases and right-of-way and the execution of a new lease.

TABLE 4-5
CURRENT CSLC LEASE FOR DCPP

Line No.	Commencement	Lease Premise(s)	Lease	Expiration
1	June 28, 2016	Discharge Channel, Intake Structure, Intake Breakwaters, & Associated Facilities	Lease No. PRC 9347.1 General Lease – Industrial Use	August 26, 2025

Lease No. PRC 9347.1 defines the Intake Structure, Breakwaters, and Discharge Structure as improvements and retains PG&E's obligation contained in the prior lease and right-of way to remove all improvements. The CSLC agreed to eliminate the time frame for removal of improvements within 90 days after the expiration of the lease:

> Lessee must remove all or any Improvements, together with the debris and all parts of any such Improvements at its sole expense and risk, in accordance with a decommissioning and restoration plan under Section 3, Paragraph 13(a)(3), regardless of whether Lessee actually constructed or placed the Improvements on the Lease Premises. Lessor may waive all or any part of this obligation in its sole discretion if doing so is in the best interests of the State. Lease No. PRC 9347.1 Section 2, Item 5.i

c. Breakwaters Removal Costs

The costs associated with the complete removal of the breakwater are summarized in Table 4-6, below, with a more detailed discussion on the removal process in DCE Section 4.1.3.2.4.

TABLE 4-6
BREAKWATER REMOVAL COSTS
(THOUSANDS OF DOLLARS)

Line No.		Labor	Material	Equipment	Disposal	Other	Grand Total
1	Cost	$18,652	$2,374	$114,526	$18,166	$132,608	$286,326

Because of salt concentration in the breakwater concrete due to years of immersion in the salt water, this concrete material is limited in its allowed reuse due to the potential for corrosive interaction with structural steel. The limited allowed reuse would require a recycling company to segregate concrete waste that has been exposed to salt water from clean concrete waste. This makes it unlikely that a recycling company would accept the breakwater concrete material, meaning it would have to be considered as waste.

It is possible that the concrete from the breakwaters could be reused in non-structural applications to improve existing roads. Potential on-site reuse of the concrete from the breakwaters was evaluated as material for improving the DCPP North Ranch Road, DCPP Primary Access Roads, 500 kilovolt Tower Access roads, and the ISFSI Transporter Route/Reservoir Road. However, prior to reuse for road surfacing, the concrete would need to be characterized through sampling and lab analysis to determine the leaching potential for chlorides and pH.

The concrete from the breakwaters could also possibly be reused to fortify the breakwaters at either the Morro Bay Harbor Entrance or at Port San Luis. Per U.S. Army Corps Engineers Shore Protection Manual, Tri-bars and Tetra-pods have been used in conjunction with rubble-mound breakwaters. However, these potential actions also require significant discretionary permitting from agencies outside of PG&E's control.

Due to the low likelihood of a recycling company accepting the breakwater material and the high uncertainty of what percentage of breakwater material may be reused on site, dependent of future salinity testing for potential leaching impacts, and uncertainty of potential offsite marine reuse, the breakwater concrete is classified as waste in this cost estimate. Its waste volume is approximately the same as all the other waste on site combined.

In addition to the costs in Table 4-6, there are environmental impacts associated with the removal of the breakwater. Removal of the breakwaters would disrupt the well-established existing ecosystem. During the evaluation of demolition techniques required to implement full removal of the breakwater, PG&E determined that underwater explosives would need to be used, which would involve significant impacts to the local ecosystem, assuming PG&E were to be able to obtain the permits to use underwater explosives at all. To the extent that established wetlands within this area are disturbed or destroyed during removal of the breakwaters, PG&E could be required to mitigate for temporal losses, and to re-create permanently lost habitat in a new location.

The removal of the breakwaters would also have a truck emissions impact from approximately 32,500 truckloads worth of waste. The breakwaters concrete has high levels of salt concentration due to years of immersion in salt water; this concrete waste is limited in its allowed reuse because of the potential for corrosive interaction with structural steel.

2. Disposal of Decommissioning Material

a. Summary

Decommissioning of a nuclear facility involves the generation of materials, including structures, components, concrete, soils, and other debris that must be dispositioned. Disposal costs are a significant portion of the overall decommissioning cost estimate. The cost is based largely on the volume of material generated during decommissioning and the disposal costs for that material. Although this cost is driven by the size of the plant Radiological Controls Area buildings, contamination levels, and building radiological release strategy, careful management and planning can help control disposal costs.

PG&E is proactively planning to manage the waste disposal process. First, PG&E plans to minimize the amount of waste generated through building demolition techniques. Next, PG&E is identifying all reasonable opportunities to: (a) reuse clean materials and thus avoid both transportation and disposal costs; (b) recycle clean materials when reuse is not a viable option and thus avoid the cost of disposal; and (c) when reuse and recycle of clean materials is not an option, to seek the lowest cost transportation and disposal options available. PG&E's goal is that clean materials stay clean and are not mixed in with higher level waste.

In addition to actively managing clean materials, PG&E has a strategy to minimize the costs of disposing of radiological materials.

Since the least expensive radiological materials to dispose of are those materials containing the lowest radiological activity concentrations, PG&E will minimize the higher activity Class B/C wastes and segregate Low-Activity Radioactive Waste (LARW) from Class A wastes to the maximum extent possible.

Decommissioning materials fall into three basic categories:

Radiological material: Material that contains radioactive contaminants from the operation of DCPP that exceed established limits. Radiological material must be shipped to an NRC licensed facility.

Hazardous/regulated materials: Material that contains other regulated substances, such as asbestos, lead, or mercury. Hazardous wastes must be disposed of at a facility designated as a hazardous landfill and are destined to be shipped out-of-state. A subcategory of this waste is “mixed waste” that contains both hazardous and radiological materials. Mixed wastes must be shipped to an NRC licensed facility and are destined to be shipped out-of-state.

Clean materials: Materials that do not meet the criteria to be classified as radiological, hazardous, or mixed wastes. Clean materials may be evaluated for reuse (e.g., concrete for backfill), recycling (e.g., metals such as rebar), or disposal

In developing the current cost estimate, PG&E has taken substantial steps to minimize the total amount of waste, minimize the amount of high-level waste versus lower-level radiological waste by segregating higher-level wastes, and maximize reusing waste to avoid the costs of off-site disposal.

b. Waste Reduction Through Building Removal Techniques

Over the last three decades, the nuclear industry has adopted several approaches to nuclear facility building decontamination and demolition of structural steel and concrete to meet free release criteria. The decontamination methods include:

- Mechanical decontamination, such as scabbling;
- Chemical decontamination to reduce the contaminants to the free release criteria prior to demolition; and

- Commodity removal to completely remove non-structural highly contaminated components.

By sequencing the demolition, meaning to demolish clean buildings first, then contaminated buildings, plants have been able to minimize the waste generated and optimize the schedule for removal of the waste. This leads to cost efficiencies and is better for the environment. After removing large or highly contaminated components, most plants have chosen aggressive techniques to remove concrete to lower contamination levels to allow lower cost disposal rather than to spend the time to completely decontaminate the concrete. Contamination in cracks and construction joints was found to require significant time and effort to fully mitigate, adding to the overall decommissioning costs. Aggressive techniques include using of hydraulic-rams to rapidly remove large thicknesses of concrete instead of taking multiple passes with a concrete shaver (scabbling). The DCE Section 4.1.3. provides detailed information on decontamination methods.

PG&E has elected to use a combination of all three methods based on input from industry experts, to prepare for Open Air Demolition (OAD), which is the fastest and most cost-effective way to demolish large buildings in preparation for dispositioning the resultant materials. Prior to OAD, the structures will be evaluated to quantify both radiological and hazardous/regulated materials contained inside. Limits for each type of hazard will be developed to ensure the continued protection of the workforce, public, and environment during OAD.

The buildings will then be separated into different categories to ensure the waste is segregated properly. Clean concrete will be used for backfill, if appropriate; all other materials will be recycled or disposed of in an appropriate landfill.

In buildings with contaminated systems/areas, the highly contaminated systems or large components will be removed first, then they will be decontaminated or sealed in place. Examples of a large contaminated component are the steam generators or reactor coolant pumps. If any hazard exceeds the limit, then the hazard is further mitigated prior to OAD. Residual concrete surfaces of impacted structures would be decontaminated by using an abrasive, or scabbling would be used to lower contamination levels in these areas. Similarly, residual structural steel surfaces of impacted structures will be decontaminated to a bare bright finish by abrasive blasting or mechanical abrading. Once all hazards are below the established limits, OAD can proceed.

This method minimizes cross-contamination of other areas when a building is demolished, which would potentially increase disposal costs. The building and remaining components will be demolished at the same time. The resultant demolition material will then be loaded and transported to a waste or recycling center as appropriate. Clean material will be kept segregated from radiological and hazardous/regulated material to prevent cross contamination that would result in cost increases with disposal.

PG&E has preliminarily identified all buildings on site and initially categorized them into these categories.

- Category 1: Structures that require little or no decontamination or hazardous material removal.
- Category 2: Structures that require significant amounts of preparation.
- Category 3: Large structures that are unique and have significant amounts of preparation work.

Category 1 and 2

During OAD, Category 1 and 2 structures will first be demolished down to each structure's floor slab elevation. During this period, the Demolition Group will segregate the demolition debris to the greatest extent practicable. Clean concrete rubble from demolition will be used as backfill and other uses on site to the extent possible. To minimize potential environmental concerns (pH issues) with concrete backfill, PG&E assumes that the concrete will be blended with soil at a rate of 5:1 (soil to concrete). Reuse of concrete was approved by the County of San Luis Obispo in the Chevron/Estero Marine Terminal Source Removal Project. However, PG&E expects there will be more clean concrete generated from decommissioning activities than the site can use for backfill. This excess debris will be transported to the Pismo Beach Railyard. Contaminated debris will be sent to an area designated by the Waste Operations Group for packaging and required documentation.

The subsequent removal of the remaining Category 1 and 2 structures will occur once the Final Status Survey (FSS) Plan has been developed by the Final Site Restoration Group and any required surveys conducted.

Category 3

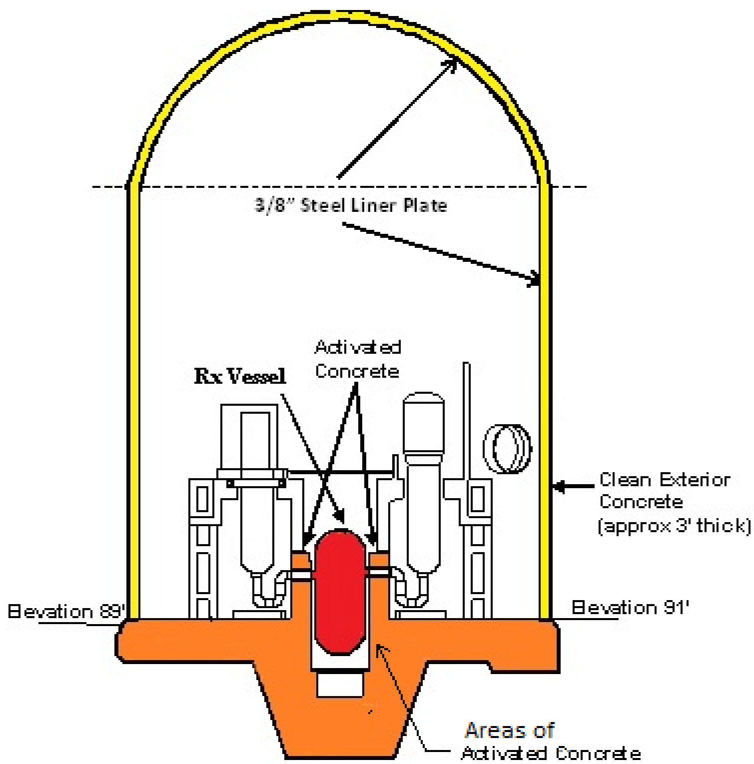
The Intake Structure is large and unique. It will be demolished when it is no longer needed for site operations. As is the case with the disposal of the breakwater's concrete discussed above, this material will not be reused or recycled due to its salt content from years of contact with the ocean.

The demolition of the Containment Buildings, Turbine Building, and Auxiliary Building, which include the Fuel Handling Buildings and the Discharge Structure, will begin after all of the SNF, special nuclear materials, and GTCC waste have been transferred to the ISFSI.

The Containment Buildings at the DCPP site are unique in that they are not occupied during the plant's operation. The buildings are typically only accessed when the plant is shut down for periods such as refueling outages every 18 months. During operations, some containment surfaces may become contaminated due to minor amounts of system leakage. When the plant is shut down for an outage, the accessible surfaces are decontaminated.

Certain parts of the structures' interiors have limited accessibility or small concrete cracks below the surface that remain radiologically contaminated. The containment building exteriors are not expected to be contaminated because they have a steel liner plate that serves as a barrier—preventing contamination that's on the interior surfaces from migrating into the buildings' outer shell. These liners will be left in place until the interior is demolished to prevent contamination of the exterior shell. The liners will then be decontaminated. With this sequence the exterior dome of containment is expected to remain clean material and be available for repurposing on site. See Figure 4-4.

FIGURE 4-4
CONTAINMENT



The concrete and steel around the Reactor Vessel is expected to be activated from years of power operations. The activation comes from years of neutron exposure with the concrete around the reactor vessel while it is producing power. Activated concrete cannot be decontaminated, and therefore, is radiological material. The activation of the concrete around the reactor vessel and years of work in containment make the interior of containment concrete a waste that cannot be reused or recycled.

c. Disposal of Material

Prior to demolition, material slated for removal from the site will be evaluated to identify what can be repurposed (or reused), recycled, or disposed of as waste. This approach minimizes costs and is environmentally responsible. Where possible, materials generated during decommissioning will be prioritized for reuse, then recycle. Materials designated for reuse are those clean materials that have another use on-site, avoiding transportation and disposal costs and the associated environmental impacts with transportation and off-site disposal. Materials designated for recycling will be clean materials that still possess usable value but are not useable on-site, incurring transportation costs but no disposal costs. Off-site disposal will be considered in cases where neither reuse or recycling is possible because the material contains radiological or hazardous/regulated contaminants, is not suitable for recycling, or when it is not economical.

Demolition methods and handling techniques will be selected to minimize cross-contaminating clean materials with those required to be disposed of as wastes. To minimize cross-contamination with clean materials, the clean materials will be removed first and segregated from the transportation and storage areas used for radiological or hazardous/regulated materials.

Concrete, for example, was used extensively during DCPP's construction. Most of the non-marine concrete is clean and can be reused at the site for fill, avoiding both transportation and disposal costs. To minimize potential environmental concerns (pH issues) with concrete backfill, PG&E assumes that the concrete will be blended with soil at a rate of 5:1 (soil to concrete). Reuse of concrete was approved by the County of San Luis Obispo in the Chevron/Estero Marine Terminal Source Removal Project. There is more clean concrete than is needed for fill; and the remaining concrete will need to be transported to a recycler. Recycling the excess concrete is more cost effective than disposing of it because only transportation costs are incurred. Last, a small fraction of the concrete slated for removal from the site will exhibit some radiological characteristics that renders the material unsuitable for reuse or recycling. Those materials will be disposed as radiological waste.

An overall goal of DCPP decommissioning is to reduce the amount of material that is disposed of in a landfill/burial facility. PG&E has evaluated the site and detailed the types and quantities of each material on site to determine the lowest cost option, including what quantities of material could be recycled or reused on-site instead of shipped offsite for disposal. PG&E determined the estimated cost of disposal based on the type and amount of material, disposal location, and transportation method.

Several transportation methods were evaluated—including trucking, barging, and rail. PG&E determined that it is cost effective to use a combination of trucks and rail. Some disposal or recycling centers cannot receive rail cars; therefore, in these cases, trucking was selected. Rail was the preferred option for radiological waste because the disposal sites that can receive this waste have rail spurs; this option also reduces the impacts to roads and the environment due to lower emissions.

While work boats and barges could be used during DCPP decommissioning to assist in the removal of the intake and discharge structures, east and west breakwaters, and to transport waste materials from the project site to ports in either Southern or Northern California their use presents additional regulatory, operational, and cost challenges.

In review of state regulations and mitigation measures from the San Onofre Nuclear Generating Station (SONGS) draft environmental impact review (EIR), PG&E determined that the use of work boats and barges would present several challenges for the DCPP decommissioning project. The SONGS draft EIR proposes as a mitigation measure that all barges and work boats to be used during the SONGS decommissioning project originate from ports located within California. The restriction of marine vessels to specific harbors reduces the likelihood of vehicle availability and is potentially cost-prohibitive as there are a limited number of marine work vessels in California.

Additionally, while the SONGS draft EIR proposes extensive mitigation measures to limit the spread of non-native marine species, the DCPP coastline has been touted by many as pristine and virtually untouched and is not exposed to such risks today. The use of work boats and barges from local ports still has the potential to introduce invasive marine species into this pristine environment. The introduction of non-native marine species can result in permanent changes to the coastal environment and marine community; several local groups have expressed explicit interest in preserving this area, and introducing this risk does not result in favorable tradeoffs for operations or other considerations.

The use of barges to transport waste materials offsite present two additional challenges not easily overcome: greenhouse gas emissions from barges during transport of waste to a nearby port and the potential for waste to be discharged to the ocean during an accident. The use of marine barges for transport of waste from DCPP to a local port (likely Port Hueneme) would result in a significant increase of air emissions, as the trip would be over approximately 125 nautical miles vs. the nearby rail spur in Pismo Beach, California. The SONGS decommissioning project will not be using barges for waste transport, even with several local ports available with significantly shorter travel distances.

Finally, the costs to retrieve any waste discharged into the ocean during an accident would likely be significant, if even technically feasible, with both the risks and costs outweighing any potential costs savings versus hauling waste offsite by truck.

Further details can be found in DCE Section 4.1.1.7.

1) Radiological Material

There are five types of radioactive waste listed below, in ascending order of contamination and unit disposal costs:

LARW is radioactive waste in which there is minimal detectable activity, where the level does not cross the lower threshold of Class A waste definition parameters. It will be disposed of as 10 CFR 20.2002 waste. Although 10 CFR 20.2002 waste is radioactive waste, it is not LLRW.

Class A waste is radioactive waste in which the radiological activity concentration is easily detectable and does not exceed 0.1 times the value in Table 1 of 10 CFR 61.55.

Class B is waste that must meet more rigorous requirements, as set forth in 10 CFR 61.56. The physical form and characteristics of Class B waste must meet both the minimum and stability requirements.

Class C waste has increasing levels of activity as compared to Class A; it exceeds 0.1 times the value in Table 1 of 10 CFR 61.55, but does not exceed the values in Table 1; it not only must meet more rigorous requirements on waste form to ensure stability, but it also requires additional measures at the disposal facility to protect against inadvertent intrusion. The physical form and characteristics of Class C waste must meet both the minimum and stability requirements set forth in 10 CFR 61.56.

GTCC is waste in which the radiological activity concentration exceeds the value in Table 1 in 10 CFR 61.55; the waste is not generally acceptable for near-surface disposal; it is managed the same as high level radioactive waste. There are no licensed facilities that can accept GTCC waste; and, therefore, will be stored in the ISFSI. The generation and packaging of GTCC waste is discussed in DCE, Section 4.1.1.4. and Section 4.1.2.3.1.

Currently, there are three licensed facilities that can accept DCPP radiological material for disposal in the U.S.: Clive Disposal Facility in Clive, Utah; Waste Control Specialists LLC in Andrews, Texas and US Ecology in Grand View, Idaho. Each of these facilities can receive different types of radiological materials. To the extent practical, PG&E will minimize the generation of Class B/C waste in order to avoid the high cost of disposing it. Further, much of the material that is potentially contaminated is expected to have very low radiological contamination, below Class A, known as LARW.

The Idaho facility is currently the most cost-effective facility available to DCPP and licensed to accept this LARW waste. PG&E will attempt to segregate this LARW material from the material that meets the Class A criteria because it can be disposed of at one-fifth the cost of Class A waste. PG&E estimates that there will be about

60 percent more LARW waste than all of the Class A waste. Taking into account the different locations and disposal costs, disposing of LARW waste is about 75 percent less expensive than disposing of that same waste if it were classified as Class A waste. Segregation activities and proper classification of the waste would result in a cost avoidance of approximately $470 million. The costs of the various disposal options are depicted in the confidential version of the DCE Table 3-9 Radiological and Hazardous Materials Disposal Costs.

There are no facilities in the U.S. that can receive GTCC wastes. The GTCC wastes will be packaged in containers similar to those used for packaging of SNF in order to provide for safe on-site storage and to ensure that the material is isolated from the environment. Ultimately, PG&E believes the GTCC wastes will be transferred to DOE or some other federally licensed final repository.

2) Hazardous Material (Excluding Mixed Waste)

The most common hazardous materials include asbestos, lead, mercury, and PCBs. Suitable disposal locations were identified for the cost estimate. For detailed cost information see DCE Section 4.1.1.3.

3) Clean Material

Clean Material is non-radiological/non-hazardous material that fall into one of three categories:

1. Reusable concrete material
2. Recyclable materials, which include two primary categories:
    a) Concrete
    b) Metals, both ferrous and non-ferrous
3. General demolition debris

PG&E plans to disposition clean materials by one of the following methods:

<u>Reuse</u>

A significant portion of the clean concrete rubble will be reused on site. The material will be crushed and screened on-site by the Materials Management Group and then used as backfill during the final site restoration phase. All clean concrete rubble in excess of the required backfill quantity will be shipped off-site as recycled material to avoid disposal costs. Reuse material will be blended with soil as described above. This reuse results in a significant amount of avoided transportation costs from the site.

Recycle

By recycling clean waste, selling certain items for reuse or to a recycling center, PG&E reduces disposal fees and the environmental impact of decommissioning. The current assumption for determining the cost of recycling non-radioactive material includes utilizing a truck to transport the items. The recycling centers are out of state in Nevada or Utah. Non-radiological metallic materials, ferrous and non-ferrous, will be sold to a metal recycler that will provide the metallic materials to an end user. The local and regional recycling companies function as brokers, processing and/or sizing the material before moving the scrap to larger companies, which in-turn typically move the scrap to international locations through the Ports of Oakland or Long Beach in California. See DCE Section 4.1.1.8. for further discussions on material management.

Every company or broker involved in the metal scrap chain between the site and the recycling endpoint further depletes the scrap value because of compounded costs for their handling, transport further down the line and profit. For example, steel sold to a local buyer that ends up in Asia would have appreciable hidden cost buried in the gross steel value offered by the local scrap (e.g., brokering) dealer. For this reason, PG&E has determined that the most economical approach to moving metal scrap is to sell and transport it directly to the end buyer. Salt Lake City has the closest large recycler of steel. There currently are no large steel recyclers in California. Steel is about 10 percent of the overall waste material on site.

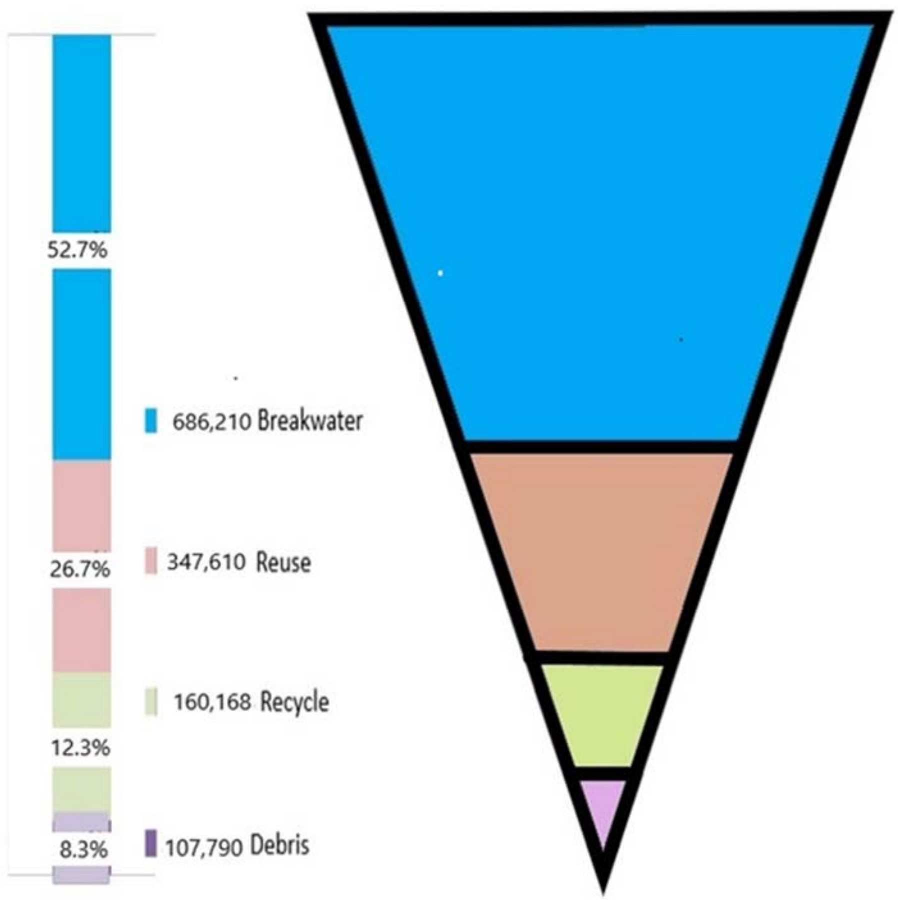
Concrete that cannot be reused on site will be trucked to a recycler in Las Vegas. This is the closest large recycling facility for concrete that can support the volume of concrete that will be recycled.

Disposal

Clean general debris that is not suitable for reuse and recycling (e.g., drywall, ceiling tile and wood) will be shipped to a landfill in La Paz, Arizona, which is determined to be the most appropriate location because of its proximity to the DCPP site and that it can take the general debris via rail.

The relative volumes of clean wastes are depicted in Figure 4-5 Clean Material Disposition.

FIGURE 4-5
CLEAN MATERIAL DEPOSITION
(IN TONS)



d. California Executive Order D-62-02

Disposal of nuclear decommissioning waste within California with radiological levels below those that are covered by NRC regulations has been a contentious issue for several decades.

In September 2002, then-governor Davis issued California Executive Order D-62-02 in response to Senate Bill (SB) 1970. The Governor vetoed the bill and wrote:

> This bill redefines the term 'radioactive waste' to include any discarded decommissioned material with the slightest trace of detectable radioactivity not attributable to background sources, and prohibits all such material from being disposed of at all existing hazardous or solid waste disposal facilities in the State of California.

After vetoing SB 1970, the governor issued Executive Order D-62-02 which states the Department of Health Services (DHS) has been directed by court order to conduct a California Environmental Quality Act (CEQA) review:

> …including an assessment of the public health and environmental safety risks and the threat to California's ground and drinking water associated with disposal of decommissioned material.

The Executive Order directed DHS to promulgate regulations for the disposal of "decommissioned materials" at California licensed sites. It defined decommissioned materials as:

> …materials with low residual levels of radioactivity that, upon decommissioning of a licensed site, may presently be released with no restrictions upon their use…

The Executive Order also directed the State Water Resources Control Board and the Regional Water Quality Control Boards (Water Boards) to impose a moratorium on disposal of decommissioned materials into Class III landfills and unclassified waste management units. The moratorium is to remain in place until the DHS completes its assessment of the public health and environmental safety risks associated with the disposal of decommissioned materials and adopts regulations setting dose standards.

In testimony on March 7, 2003, when asked where facilities should dispose of decommissioned materials, Dr. Diana Bonta, Director of the DHS, testified that *"…facilities can certainly remove the [decommissioned] materials to a licensed, low-level radioactive site* *which would be out of state.*" She further testified that DHS would be completing a CEQA review and determining what should be the proper level for disposal in a safe fashion. Her testimony provided no guidance on safe levels for disposal and left open the possibility of a complete prohibition on decommissioned material being placed in a landfill in California.[2]

DHS was re-organized in 2007, creating the Department of Health Care Services and the Department of Public Health. Neither department has begun the CEQA review and regulatory actions required by the Executive Order, and the moratorium remains in place. In the 2015 NDCTP, the Commission directed PG&E to consult with various state agencies as to "the application of Executive Order D-62-02 to decommissioned material at DCPP."[3] PG&E Prepared Testimony, Chapter 5, Section E discusses PG&E's recent agency communications with various state agencies with respect to Executive Order D-62-02.

It would never be appropriate for decommissioned material to be disposed of in a Class III facility, which is a municipal landfill that is not authorized to accept hazardous waste. There are four Class I disposal facilities and eight Class II disposal facilities holding active licenses in California. Two of the Class II facilities accept only waste from within their county. This leaves four Class I and six Class II facilities as possible disposal options.

For reference purposes, PG&E estimated the cost differential if PG&E were able to dispose of this material in state. To be clear, PG&E does not believe in-state facilities will accept this material without state action. In order to compare hypothetical in-state vs. out-of-state costs for recycling and for debris disposal, PG&E used a uniform disposal rate based on published information for both in state and out of state disposal. Therefore, the only difference in cost would be for transportation. In-state transportation is assumed to be by truck, while

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2 California Legislature Senate Select Committee on Urban Landfills Public Hearing Disposal of Radioactive Waste March 7, 2003. Transcript available at: www.committeetobridgethegap.org/pdf/romero_03072003.pdf.

3 D.17-05-020, Ordering Paragraph (OP) 7.

out-of-state transportation is by rail or truck, depending on the amount to transport. The difference in costs between out-of-state vs. in-state disposal was calculated by subtracting in-state from out-of-state transportation costs. This calculation identified a total transportation cost difference of approximately $10.37 million for non-breakwater debris and recycling, and a total of $87.86 million with the breakwater debris included (see Table 4-7).

TABLE 4-7
IN-STATE/OUT-OF-STATE TRANSPORTATION COMPARISON
(MILLIONS OF DOLLARS)

Line No.	Transport Destination/ Method	General Debris	General Debris, Plus Breakwater	Recycle Concrete	
1	In-State	$6.00 (Truck)	$44.19 (Truck)	$4.89 (Truck)	
2	Out-of-State	$12.52 (Truck)	$128.2 (Rail)	$8.74 (Truck)	
3	Difference (Out-of-State minus In-State)	$6.52	$84.01	$3.85	
4	Total Difference (Out-of-State minus In-State) Without Breakwater				$10.37
5	Total Difference (Out-of-State minus In-State) With Breakwater				$87.86

In addition to the fact that the state of California has yet to establish clear guidelines regarding in-state disposal of decommissioned materials, it is reasonable to assume that in-state facilities may not be able or willing to receive the significant amount of projected waste volumes. By contrast, the disposal facilities that PG&E anticipates using for this effort all have projected continued operation and available capacity for at least 30 years, sufficient to complete the planned decommissioning. Given these circumstances, PG&E's assumption that this material will be disposed of at the disposal site in La Paz, Arizona is reasonable. This facility is also being utilized for the SONGS decommissioning project.

e. 2015 and 2018 Waste Disposal Volumes

Estimated waste disposal costs have more than doubled between the 2015 and 2018 estimates. This difference is attributable to increases in both estimated volumes of waste and estimated waste disposal rates in the 2018 DCE.

Table 4-8 compares assumed radioactive waste volumes between the 2015 and 2018 estimates. The 2015 estimate did not delineate out Low Activity Radioactive Waste (LARW) from the waste streams. Table 4-8 shows a substantial difference in assumed radioactive waste volumes between the two filings. The difference in Class A volume appears to arise from the unit-factor cost methodology used in 2015.

TABLE 4-8
WASTE CLASSIFICATION VOLUME COMPARISON

Line No.	Classification	Class A (cu ft)	Class B (cu ft)	Class C (cu ft)	LARW 20.2002 (cu ft)
1	2015 DCE	1,206,787	3,700	1,178	N/A
2	2018 DCE	3,146,643	3,784	2,800	5,019,379

PG&E was able to make a direct comparison for assumed concrete volumes. Table 4-9 provides a comparison of estimated concrete volumes associated with the Containment Structures and Auxiliary Building. PG&E also brought in a third party to provide a separate estimate for concrete waste volumes and those results are also included in Table 4-9.

TABLE 4-9
WASTE VOLUME ESTIMATE COMPARISON

Line No.	Building	Cubic Yards
1	<u>U1 Containment</u>	
2	2018 DCE	38,997
3	2018 3rd Party 3D model	34,328
4	2015 DCE	24,122
5	<u>U1 Auxiliary & Fuel Handling Building</u>	
6	2018 DCE	31,850
7	2018 3rd Party 3D model	31,509
8	2015 DCE	23,843

Waste disposal rates, the second area of differences, are confidential, and identified in the confidential version of the DCE in Section 4.1.1.7.

3. Security

a. Summary

The DCPP security cost estimate includes costs for implementing proposed security modifications, and security staffing between permanent shutdown and transfer of SNF and GTCC waste to an approved, off-site facility.

In previous NDCTPs, the Commission has expressed concerns about the basis for PG&E's determination of post-operational security staffing costs. For purposes of preparing the current estimate, PG&E first reviewed NRC requirements and PG&E's existing staffing. In order to meet PG&E's existing NRC mandated security obligations, PG&E requires 272 security Full Time Equivalents (FTE).

PG&E then evaluated security risks and vulnerabilities from the time the first unit is shut down through decommissioning. PG&E used a widely-accepted commercial 3D modeling and statistical analysis program to determine vulnerabilities, and the number of posts, or positions which must be staffed in order to protect the target areas. Once posts were determined, to ensure adequate staffing, PG&E determined the number of FTEs required to fill each post. Additionally, PG&E proactively evaluated steps which could be undertaken prior to each phase of decommissioning to obtain regulatory approvals to reduce the number of required posts.

An independent third party reviewed and validated PG&E's proposed protective plan, including the proposed security modifications.

b. PG&E Compliance With NRC Security Regulations

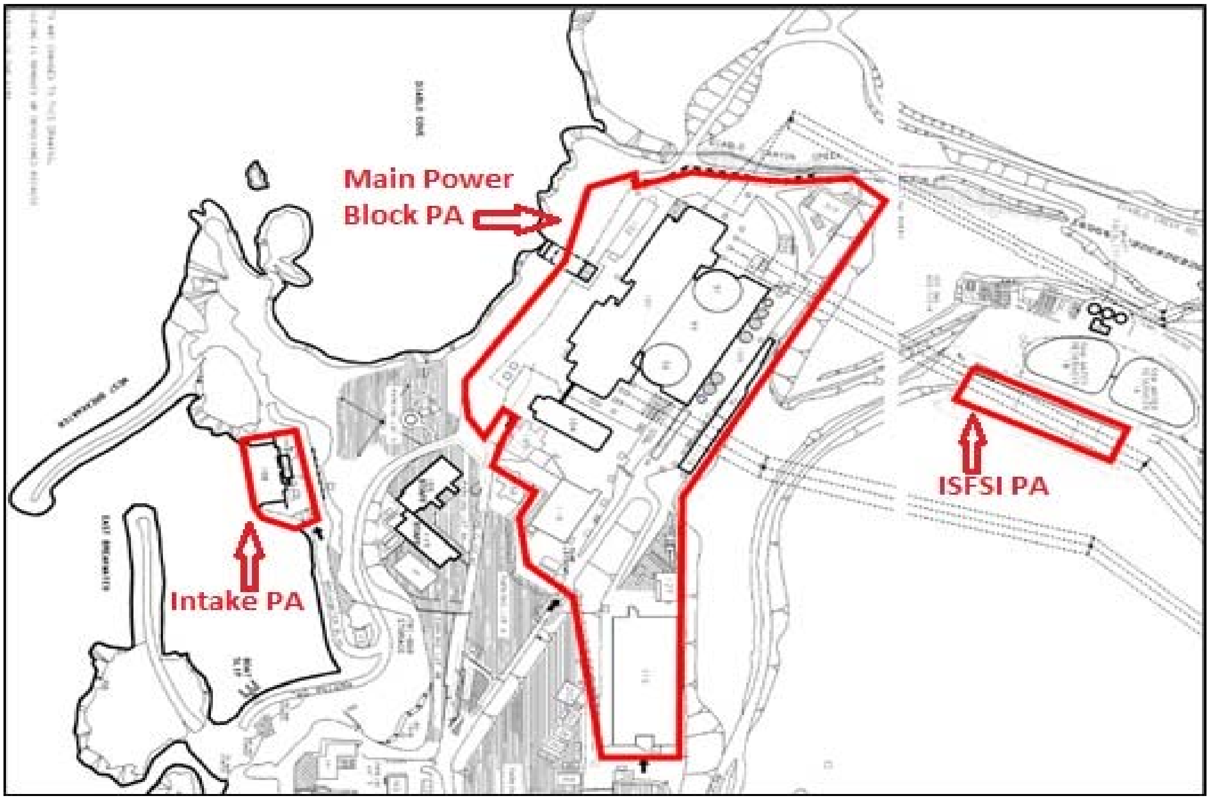
Whether the plant is operating or not, NRC regulations in 10 CFR 73.55 require PG&E to establish and maintain the capability to detect, assess, interdict, and neutralize security threats. The regulations also require a "defense in depth" approach to demonstrate the continuous effectiveness of the security program. Defense in depth is the use of multiple and diverse security measures to protect the DCPP site. In addition, PG&E must establish, maintain, and implement an NRC-approved Physical Security Plan, Training and Qualification Plan and Safeguards Contingency Plan, including amendments. PG&E is also required to control personnel access to areas that do not contain special nuclear material but may contain significant quantities of radioactive materials that could be used for nefarious purposes.

After the events of September 11, 2001, the NRC required a series of additional security measures, including increased patrols, augmented security forces and capabilities and more restrictive site access controls. These NRC requirements are contained in 10 CFR 73, various NRC orders and guidance documents and have been incorporated in PG&E's NRC-approved security plans.

PG&E also holds an ISFSI 10 CFR 72 site-specific license, which is separate from the reactor unit licenses. Security requirements for a licensee that holds a specific ISFSI license are contained in 10 CFR 73.51 and are generally less stringent than those for a reactor because of the reduced risks associated with ISFSI operations. In lieu of maintaining separate security programs for the DCPP reactor units and the ISFSI, PG&E maintains a single security program compliant with 10 CFR 73.55 for DCPP Unit 1, Unit 2 and ISFSI.

There are three protected area (PA) locations within the site boundary as shown in Figure 4-7 DCPP Protected Area Locations. The three PAs consist of the main power block PA, intake PA, and ISFSI PA. Within these areas, DCPP maintains a physical protection system and security personnel to protect identified vital equipment and structures against radiological sabotage, to prevent the theft or diversion of special nuclear material and to provide adequate protection of public health and safety from any security event described in the Site Emergency Plan.

FIGURE 4-7
DCPP PROTECTED AREA LOCATIONS



The DCPP Protective Strategy, in conjunction with the Physical Security Plan, Training and Qualification Plan and Safeguards Contingency Plan, were implemented to comply with 10 CFR 73.55 security requirements and have been approved by the NRC.

The DCPP Protective Strategy describes the detailed response types, timelines, and situational information necessary for DCPP security personnel to successfully interdict and neutralize a Design Basis Threat (DBT). The DCPP Protective Strategy identifies the internal and external security measures necessary to protect against acts of radiological sabotage, prevent the theft or diversion of special nuclear material and to provide adequate protection of public health and safety. Multiple threats and possible risk scenarios for various vital equipment and structures within the on-site protected areas are addressed as part of the protective strategy.

The Physical Security Plan describes the physical protection system and security personnel protecting the DCPP site against radiological sabotage and preventing the theft of special nuclear material.

The Safeguards Contingency Plan describes actions that will be taken to protect the DCPP site against radiological sabotage and to prevent the theft of special nuclear material.

The Security Training and Qualification Plan ensures that security personnel are trained, qualified, and equipped to perform their assigned duties as identified in the protective strategy and security plans.

Security personnel are also responsible for administrative and programmatic controls (e.g., criminal history, background checks, Fitness for Duty Program, Behavior Observation Program, and Insider Mitigation Program) that are required by the NRC to ensure the physical fitness and trustworthiness of security personnel and other critical employees.

Security at DCPP is in place 24-hours-a-day, seven-days-a-week. To implement NRC requirements, the combined pre-shutdown security staffing level at DCPP Unit 1, Unit 2 and ISFSI is 272 FTEs. The 272 FTEs include security posts, management, and support staff. Support staff includes access authorization, training, fitness for duty and other staff required to procure security-related equipment and protect safeguard information.

It should be noted that the NRC routinely conducts security inspection activities to ensure that the DCPP security program complies with 10 CFR 73.55 and is effectively implemented to protect public health and safety. In addition, the NRC conducts Force-on-Force drills to test PG&E's capability to detect and neutralize potential threats. During an NRC 2010 security inspection at DCPP, the NRC identified several security-related deficiencies; and to restore compliance, DCPP was required to install additional security equipment, and acquire supplemental security staff. While Units 1 and 2 are operating, the current level of staffing is required to ensure compliance with 10 CFR 73.55, various NRC orders and NRC guidance documents.

c. Preparation of Decommissioning Security Cost Estimate

PG&E began estimating decommissioning security costs by evaluating security risks and vulnerabilities during decommissioning. Security-related plant modifications were also identified to mitigate or eliminate potential risks and exposures, optimize security operations, and reduce security costs. Based on several factors, including risks of unintended openings, cost, duration in wet storage, and benchmarking of plants entering active decommissioning, PG&E determined that the existing protective area fence lines should remain unchanged.

To develop a post shutdown protective strategy, PG&E used a commercial 3D modeling and statistical analysis. The AVERT Software by ARES Corp results can be used to identify vulnerabilities and reduce the number of required performance-based drills and exercises to establish an optimal defensive strategy by determining ideal locations for security positions and barriers, and permitting validation by modeling removing posts until security breaking point. The AVERT software has been used to assess potential security vulnerabilities at the U.S. DOE, U.S. Department of Defense, and several commercial nuclear power plants. It is an NRC-recognized tool for performing security vulnerability assessments and is actively used by several NRC licensees to identify cost reduction measures in security operations.

PG&E modeled the DCPP site interior and exterior features and access points and simulate multiple security threat types. Various security configurations and scenarios were performed to identify potential vulnerabilities and areas where security operations can be potentially optimized. PG&E evaluated simulations to confirm the adequacy of the current security strategy and security posts, as well as those that will be set up between the times Units 1 and 2 are shut down and spent fuel is transferred to an approved off-site facility.

To validate the results, additional simulations were performed to sequentially remove security posts to identify the point where high assurance to protect against radiological sabotage would no longer be maintained. The validation simulations identified a sharp decline in the defensive capabilities after the removal of two security posts. Therefore, PG&E concluded that that the validation simulation results confirms that the defensive strategy after permanent shutdown demonstrates high assurance that adequate protection will be provided against radiological sabotage as required in 10 CFR 73.

In addition, the results were used to determine: (1) the reasonableness of several security modifications that could optimize security operations and reduce overall security costs; and (2) the best time to implement changes to the physical security system, obtain regulatory relief and reduce security staffing levels during decommissioning.

d. Independent Review of Decommissioning Security Approach

PG&E hired industry expert G4S Regulated Security Solutions Special Tactical Services (STS) to independently review PG&E's security plan. STS has an expert understanding of past and current tactics, techniques, and procedures available to the DBT adversary. Mr. Williamson, who performed the review, has conducted protective strategy reviews at numerous nuclear facilities; helped adjust strategies after identifying efficiencies and margin; designed extensive barrier plans; provided on-site consultation about all aspects of the NRC's triennial Force on Force Program; conducted exploitability analysis for unattended openings and safeguards violations; and supported the development and use of the AVERT system for nuclear-specific DBT adversary and security force response. He conducted an in-depth analysis by performing site inspections and tabletop exercises to assess the reasonableness of PG&E's application of the AVERT software, proposed security modifications, number of security posts and the overall defensive strategy. The report is provided as PG&E Prepared Testimony, Chapter 4, Attachment B.

STS concluded that:

1) PG&E's decommissioning defensive strategy is well thought out and is reasonable.
2) The use of the AVERT 3D modeling and statistical analysis results is a reasonable approach to identify the security staffing needed to

successfully protect the plant during decommissioning and storage of fuel at the ISFSI.

3) Based on the AVERT results, PG&E has identified the most efficient strategy, while maintaining a high assurance to provide protection against radiological sabotage.

4) PG&E has identified the necessary number of security posts to ensure protection of the plant in accordance with the 10 CFR 73.55 security requirements; the number will initially increase and then decrease over subsequent periods. STS noted that PG&E was attempting to avoid a costly mistake made by other decommissioning sites—reducing too many security personnel, then having to hire additional security staff later at greater cost.

STS also analyzed PG&E's proposed security modifications. To reduce security posts, PG&E originally planned to reconfigure the main protected area fencing so that the main warehouse is located outside the main protected area. The independent review concluded that doing so would have a limited cost benefit. As a result, PG&E determined that it would not be cost effective to implement the main protected area modification and eliminated it from further consideration. STS concluded that the remaining proposed security modifications would improve security response times, reduce the number of interior response positions, and reduce the likelihood of an adversary gaining access to a target set location.

e. Phased Strategy for Security

The primary security cost is staffing. In order to reduce staffing costs, PG&E has determined that, with NRC concurrence, security staffing may be based on four decommissioning periods (Periods 0, 1, 2 and 3). Periods 1, 2 and 3 align with NRC-identified decommissioning milestones in decommissioning guidance documents. PG&E added a fourth period (Period 0) to reflect the ramp-up of security-related decommissioning planning activities (e.g., preparation and submittal of NRC exemptions, license amendments) and security staffing prior to the shutdown of the second unit. The NRC Levels and DCPP comparable periods are:

- Period 0: One unit is shutdown and defueled with one unit operational. The duration of Period 0 is approximately 10 months.
- Period 1: Both units are shut down, defueled, and spent fuel is stored in the spent fuel pools. However, the spent fuel has not sufficiently cooled such that the probability of a zirc-fire accident is very low. The duration of Period 1 is approximately 18 months.
- Period 2: Spent fuel is stored in the spent fuel pools and has sufficiently cooled such that the probability of a zirc-fire accident is very low. The duration of Period 2 is approximately 5.5 years.
- Period 3: All spent fuel is stored at the ISFSI. Based on PG&E's current assumptions about DOE pickup of spent fuel, the duration of Period 3 is approximately 35 years.

During each decommissioning period, the security protective strategy will be adjusted as required to reflect the security staffing necessary to protect the site. PG&E performed a series of reviews and analyses to:

- Assess the impact of reducing the number of vital equipment and structures and determine the resulting increase or decrease in security costs to implement compensatory measures (e.g., additional posts);
- Identify security modifications that most likely would reduce security posts and create more efficient security operations.
- Identify potential NRC regulatory relief that should be sought during decommissioning. Regulatory relief consists of NRC exemption requests from security regulations, license amendment requests to modify security licensing basis documents, and requests to rescind NRC security-related orders that no longer apply to a permanently shutdown facility.

The results were used to identify the best time to implement security modifications, obtain regulatory relief and reduce security staffing levels during the decommissioning periods. As security risks and vulnerabilities decrease, security staffing levels will gradually decline.

To the extent practical, early implementation of security-related modifications is planned after permanent shutdown of the first reactor unit to optimize security operations, prepare the DCPP site for decommissioning of both reactor units and minimize the net increase in security staffing. A detailed description of each modification is included in DCE Section 4.1.1.2.3.

In addition, based on previously granted NRC security-related decommissioning exemptions, PG&E concluded that the largest reductions in security staffing may occur at the end of the zirc fire window (Period 1) driven by the implementation of security modifications; after devitalization of the control room (Period 2); and upon the transition from a 10 CFR 73.55 to a 10 CFR 73.51 security program (Period 3). As such, regulatory exemption requests are planned during the decommissioning periods associated with these milestones. To minimize potential delays in implementing security staffing reductions, the goal is to submit requested regulatory relief to the NRC at least 18 months in advance to ensure that the NRC has sufficient time to review and approve the request prior to the scheduled implementation date of the DCPP security revision.

1) Period 0: Initial Shutdown

Period 0 begins when Unit 1 is permanently shut down and ends when Unit 2 is permanently shut down. The duration of Period 0 is approximately 10 months. During Period 0, the shutdown reactor will be defueled, and the spent fuel transferred to the SFP for wet storage. The second unit will remain operational. In addition, the control room will remain operational to support operation of the second unit and Safe Storage (SAFSTOR) of spent fuel at the shutdown unit. To ensure that there is no reduction in safeguard effectiveness, the DCPP protective strategy will remain unchanged until the second reactor unit is permanently shut down and defueled.

During Period 0, the ramp-up of security-related decommissioning planning activities will begin. With the control room operational and the protective strategy unchanged, no NRC security-related exemptions are planned. In addition, no changes to the security plans are expected during Period 0 that would result in a decrease in safeguards effectiveness and require prior NRC approval.

Crystal River Nuclear Power Plant submitted exemption requests and license amendment requests to modify its physical security configuration. However, these changes were primarily to optimize SAFSTOR operations.

As described further in DCE Section 3.4.4., the security posts during Period 0 will initially be the same as the number of pre-shut-down security posts that are required to ensure that there are no reductions in safeguards' effectiveness with one unit shut down and one unit operational. As Period 0 progresses, security posts will be gradually increased to the Period 1 staffing levels. The = increase is to account for the compensatory measures necessary to protect against new security vulnerabilities that did not exist when both units were operating (e.g., new openings in structures to facilitate equipment removal and draining piping that was previously filled with water).

Planned security modifications during Period 0 have been evaluated to ensure that there will be no impact on the operating reactor unit. The security modifications scheduled to be implemented during Period 0 include:

- Installing a "kicker" on the main protected area fence to make it more difficult for an adversary to access the area;
- Reconfiguring the delay fence inside of the main protected area to provide additional time for security to deter or stop an adversary;
- Backfilling the shutdown unit intake tunnel with dirt or concrete to protect the unattended openings;
- Removing siding from the shutdown unit buttress to improve line of sight and enhance the ability to detect and neutralize potential security threats;
- Constructing and installing fighting positions in the shutdown unit to provide protection for internal responders from an adversary, maintain a good defense in depth and provide

continued high assurance of the ability to neutralize an adversary; and

- Sealing doorways in the shutdown unit that will no longer be used. With fewer travel routes to access vital equipment and structures, security staff will be able to execute the protective strategy with fewer responders.

2) Period 1: Wet Storage During Zirc Fire

Period 1 begins after permanent shutdown and defueling of the second reactor unit and terminates at the end of the zirc-fire window with spent fuel in the pool. The duration of Period 1 is approximately 1.5 years. All spent fuel is in wet storage, the control room remains operational to support SAFSTOR of spent fuel until the end of the zirc fire window, and decommissioning activities are underway.

During Period 1, the protective strategy will be modified to ensure adequate protection of spent fuel and continuous compliance with 10 CFR 73.55 during the zirc-fire window. To minimize the net increase in security staffing, vital equipment in the shutdown unit that is no longer in use will be de-vitalized and security modifications will be implemented to reduce security posts.

Changes to the security protective strategy and security plans are expected to reflect the shutdown units and installation of security modifications. NRC review and approval will be sought prior to implementation of any security-related change that could potentially result in a reduction in safeguard effectiveness. While the control room is operational, PG&E does not plan to implement NRC security-related exemptions.

During Period 1, security staffing levels take into account both the additional security posts and compensatory measures necessary to protect against new security vulnerabilities with both reactor units shutdown and the efficiencies gained after early decommissioning activities.

There are 52 security posts required during Period 1 to protect the DCPP site. Thirty of them are required to implement the DCPP protective strategy. These 30 posts consist primarily of security officers who are stationed and/or patrolling at various locations throughout the plant. An additional eight administrative posts are required for access control to the DCPP site and, DCPP protected areas, security escorts and coordination/control of vehicles that access the DCPP site. The administrative posts are also staffed by security officers. Three supervisory posts are required to manage, coordinate and plan work for security resources. An additional 11 posts are staffed by relief officers who are required to comply with California labor laws. Relief officers provide continuous coverage to support California labor law by providing required break and meal times.

Security labor costs are presented as security FTEs. Section 3.f. below discusses how PG&E converts posts to FTEs. The 52 posts equate to 289 FTEs. The 289 FTEs include an additional 17 FTEs, compared to the Period 0 security staffing levels. The increase is needed to protect against new security vulnerabilities that did not exist with both units operating. For example, empty intake and discharge tunnels require as many as 25 FTEs for continuous monitoring. These compensatory measures will be eliminated after the tunnels are backfilled with dirt and concrete.

During Period 1, unit-specific and common area security modifications will be implemented to minimize the net increase in security staffing because of efficiencies gained in security operations and/or elimination of potential vulnerabilities. Examples of planned security modifications during Period 1 include:

- Backfilling the second shutdown unit intake tunnel and common discharge tunnels with dirt or concrete to protect the unattended openings;
- Installing delay cages/gates for the personnel and roll-up doors in the Turbine Building, Auxiliary Building and Fuel Handling Building to give external responders more time to engage an adversary attempting to breach the delay cages and reduce the

likelihood of an adversary gaining access to vital equipment and structures;

- Removing the 140’ pedestrian bridge (and associated electrical conduits and other structural items) that extends between the Administration Building to the Turbine Building to help early detection of a potential adversary and reduce the likelihood of an adversary gaining access to vital equipment and structures;
- Removing the siding from the second shutdown unit buttress to improve line of sight and enhance the ability to detect and neutralize potential security threats;
- Constructing and installing fighting positions in the second shutdown unit to provide protection for internal responders from an adversary, maintain a good defense in depth and continue to ensure the ability to neutralize an adversary; and
- Sealing doorways in the second shutdown unit that will no longer be used. With fewer travel routes to access vital equipment and structures, security will be able to execute the protective strategy with fewer responders.

3) Period 2: Wet Storage Post Zirc Fire

Period 2 begins after the zirc fire window and ends after all spent fuel is transferred to the onsite ISFSI. The duration of Period 2 is approximately 5.5 years. All spent fuel is in wet storage as decommissioning activities progress. During Period 2, the control room will be devitalized at the end of the zirc fire window. In addition, a protective strategy will still be required to ensure continuous compliance with 10 CFR 73.55 and adequate protection of spent fuel.

Prior to Period 2, the majority of planned and designed security modifications will have been implemented to eliminate vulnerabilities associated with the shutdown plants. During Period 2, de-energized overhead transmission lines will be removed, eliminating a potential way for an adversary to access the protected area. Compensatory measures will be required until the de-energized overhead lines are removed.

To reduce overall security costs and security staffing levels, the DCPP protective strategy will be revised to consolidate or eliminate some security operations and functions, reflect implementation of security modifications, and incorporate approved regulatory relief from NRC security requirements that are no longer applicable. The following exemption requests will be prepared and submitted to the NRC in Period 1 and implemented in Period 2 after the decay heat associated with spent fuel has sufficiently decreased such that the probability of a zirc fire accident is very low.

- 10 CFR 73.55(b)(3) that requires protection against significant core damage. With the reactor units defueled, the requirement is no longer applicable.
- 10 CFR 73.55(e)(9)(v) that requires the control room to be a vital area. A control room is no longer required after permanent shutdown and defueling.
- 10 CFR 73.55(j)(4)(ii) that requires continuous communications between the central alarm station and the control room. A control room is no longer required after permanent shutdown and defueling.

The exemption requests will be submitted to the NRC at least 18 months in advance to minimize potential delays in implementing security staffing reductions. Sufficient industry precedent exists to support these requests.

Security staffing will remain unchanged until PG&E obtains all required NRC approvals. Once obtained, reductions will be made. With the control room devitalized and the zirc fire window no longer a concern, the number of security posts is expected to decrease to 39 during Period 2. Twenty of the 39 posts will be required to implement the DCPP protective strategy. The eight administrative posts and three supervisory posts will still be required to provide the same functions as described in Period 1. With fewer posts needed to implement the protective strategy, the relief posts will be reduced to eight. Similarly, the total posts, including relief posts, are converted to FTEs. During Period 2, security staffing is expected to decrease from 289 to 207 FTEs due to the reduced security risks with both reactor units shutdown. For example, the 25 FTEs added in Period 1 that provided continuous monitoring of the intake and discharge tunnel openings will be eliminated after the tunnels are backfilled with dirt or concrete.

4) Period 3: Dry Storage (ISFSI Only)

Period 3 begins after the wet storage period (after all spent fuel is transferred from the SFPs to the ISFSI) and ends after all spent fuel and GTCC is transferred to the DOE. The duration of Period 3 is approximately 35 years. During Period 3, decommissioning of the reactor units will continue until the NRC licenses are terminated.

After highly radioactive materials are removed from the DCPP reactor sites, the DCPP nuclear security footprint will be limited to the protection of the ISFSI only, and the focus of the protective strategy will be protecting the spent fuel and GTCC stored at the ISFSI. As such, the required nuclear security staffing in this period is significantly diminished.

PG&E intends to submit an exemption request from the 10 CFR 73.55 security requirements, such that PG&E can transition to a 10 CFR 73.51 security program for a stand-alone ISFSI. A 10 CFR 73.51 security program is subject to less stringent requirements than a 10 CFR 73.55 security program because of the reduced risks associated with ISFSI operations.

Security staffing levels will significantly decrease after the transition from a 10 CFR 73.55 to a 10 CFR 73.51 security program. In addition, the security organization will be restructured, and the security staffing levels will be substantially reduced from the 207 FTEs in Period 2. During Period 3, security functions will primarily be performed by management and/or supervisory personnel working 12-hour shifts; no relief posts are included. The security organization will consist of six security posts supported by a total of four security administrative and managerial personnel. The six posts, converted to FTEs, plus the security administrative and managerial personnel total 29 FTEs. The combined benefits associated with an exemption from 10 CFR 73.55, the transition to a 10 CFR 73.51 security program and restructuring of the security organization will result in significant reductions in security staffing levels and overall security costs.

The 10 CFR 73.51 ISFSI nuclear security program will remain in effect until the spent fuel and GTCC waste is transferred to DOE. Afterward, PG&E may seek an NRC exemption from all nuclear security requirements, or the nuclear security program will terminate with the ISFSI license, whichever occurs first.

f. Security Staffing Projections

The DCPP protective strategy, as approved by the NRC, is the primary basis for determining the number of DCPP security posts necessary to protect the site in accordance with 10 CFR 73.55. Prior to permanent shutdown of the second unit, decommissioning activities will be limited to ensure that there is no impact on the operating unit. After permanent shutdown of the second unit, full-scale decommissioning will begin. To reflect the initial reductions in security staffing (stated in number of posts and FTEs) after permanent shutdown of the second unit, Period 1 security staffing is presented as Period 1a and Period 1b. Period 1a shows the security staffing immediately after shutdown of the second unit. During Period 1a, plant equipment that is no longer in use will be devitalized. In addition, an evaluation of the security protective strategy will be performed. Regulatory approvals will be sought where required for changes that could potentially reduce the safeguards effectiveness. Period 1b shows the security staffing after implementation of identified changes in Period 1a, including the NRC approval, as required, for the updated protective strategy.

Security posts are the security personnel that are needed to implement the DCPP protective strategy and perform site-specific security functions (e.g., communication with local law enforcement and incident response times). Staffing projections also include relief posts to meet the California labor requirements (non-work hour requirements and benefits (e.g., breaks, vacations and holidays); PG&E bargaining agreements and administrative posts that are responsible for maintaining and executing the access authorization program, fitness for duty program and ancillary security duties, such as vehicle escorts; and managerial posts to supervise security personnel.

Table 4-10 provides an estimate of the number of security posts for the four DCPP decommissioning periods. Security modifications are summarized in each decommissioning period and detailed descriptions of each modification is included in DCE Section 4.1.1.2.3. The security staffing costs for period 0 are not included in DCPP Decommissioning costs.

TABLE 4-10
DCPP DECOMMISSIONING SECURITY POSTS

DCPP Periods	Period Duration	Posts					
		Protective Strategy	Security Support (24/7 shift)	Security Support (10 hr shift)	State Law Relief	Supervision	Total
0 Initial Shutdown Set Note 1	8 months	See Note 2	2	6	See Note 2	3	See Note 2
1a Zirc-Fire	18 months	30	2	6	11	3	52
1b Zirc-Fire		29	2		11		51
2 Post Zirc-Fire	5.5 years	20	2	6	8	3	39
3 ISFSI Only	35 years	5	0	0	See Note 3	1	6

Note 1: Period 0 posts are not included in Decom costs.

Note 2: Safeguards Information.

Note 3: All management personnel working 12-hour shifts with no relief posts.

To determine the number of personnel required, PG&E first determined the number of security posts required during each period. To ensure adequate staffing, each security post requires 5.5 FTEs for continuous coverage (24 hours/day, 7 days/week) and 1.5 FTEs for each 10-hour shift. In addition, one relief post is assigned to every four posts to account for personnel breaks in accordance with California labor laws. For example, assume 12 security posts are required. The equivalent FTEs for security posts are shown in Table 4-11.

The 5.5 multiplier for 24/7 shifts and the 1.5 multiplier for 10-hour shifts begin with the number of FTE's required to fill the post (4.2 & 1.0, respectively) per year. Afterwards, the multipliers, based on empirical data from 2017, consider all non-productive time including vacations, sick time, employees on disability, employees on maternity leave, employees on paternity leave and jury duty.

TABLE 4-11
EQUIVALENT FTE(S) PER SECURITY POST(S)

Line No.		Shift Duration	Posts	Full Time Equivalents (FTEs)
1	(1)	24 hrs	12	(12 posts + 12/4 relief posts) x 5.5 = 82.5 FTEs
2	(2)	12 hrs	12	(12 posts + 12/4 relief posts) x 1.5 = 22.5 FTEs

The estimates of projected security staffing levels are shown in Table 4-12 and 4-13. Table 4-12 shows the pre-shutdown and the decommissioning staffing levels for specific milestones when major changes in security staffing are anticipated. The pre-shutdown security staffing levels, which reflect both reactor units and the ISFSI, are shown for comparison with the decommissioning periods. During each decommissioning period, staffing levels will fluctuate as risks are reduced and security modifications are implemented. The milestones correlate to the peak staffing levels that are expected to occur during each period and are based on conservative assumptions of the decommissioning status at the beginning of each period.

Table 4-12 includes the security officers, support personnel, supervisors and management needed to support decommissioning operations, to implement security-related modifications, and to revise security protective strategy and supporting documents for submission to the NRC.

The Period 3 security staffing levels are shown in Table 4-13 to reflect the realignment of security resources during dry storage.

TABLE 4-12
DCPP REACTOR DECOMMISSIONING SECURITY STAFFING PROJECTIONS (FTES)

<table>
<tr><th>Milestone</th><th>Period</th><th>Officers</th><th>AA/FFD</th><th>Training Staff</th><th>On-Shift Supervisors</th><th>Other (Management and Support)</th><th>Total Staffing</th></tr>
<tr><td>Pre-Shutdown</td><td>N/A</td><td>211</td><td>5</td><td>10</td><td>26</td><td>20</td><td>272</td></tr>
<tr><td>One unit defueled, no plant mods; no NRC regulatory approvals</td><td>0</td><td>211</td><td>5</td><td>10</td><td>26</td><td>20</td><td>272</td></tr>
<tr><td>Both units defueled, no plant mods; no NRC regulatory approvals</td><td>1a</td><td>244</td><td rowspan="2">5</td><td rowspan="2">8</td><td rowspan="2">20</td><td rowspan="2">12</td><td>289</td></tr>
<tr><td>Both units defueled, no plant mods; and NRC regulatory approvals</td><td>1b</td><td>238</td><td>283</td></tr>
<tr><td>Both unit(s) defueled, with plant mods; and NRC regulatory approvals</td><td>2</td><td>173</td><td>5</td><td>5</td><td>20</td><td>4</td><td>207</td></tr>
<tr><td colspan="8">AA – Access Authorization FFD – Fitness for duty
Other – Security Director and Managers (e.g., Operations, Strategy, Programs)</td></tr>
</table>

TABLE 4-13
DCPP ISFSI SECURITY STAFFING PROJECTIONS (FTES)

<table>
<tr><th>Milestone</th><th>Period</th><th>Specialist/ Leads</th><th>Director DCPP and Humboldt Bay Power Plant (HBPP)</th><th>Security Ops Mgr</th><th>AA/FFD</th><th>Security Training & Weapons</th><th>Total Staffing</th></tr>
<tr><td>Stand-alone ISFSI</td><td>3</td><td>25</td><td>1</td><td>1</td><td>1</td><td>1</td><td>29</td></tr>
<tr><td colspan="8">Specialists/Leads: Management/supervisory personnel that perform security functions.
Notes: The following functions are captured in the Staffing support plan: ISFSI/I&C/Security Engineer, Procurement/Work Control.
The EP Coord & SGI Coord functions are captured in the Security Ops Mgr position.</td></tr>
</table>

g. DCPP Total Security Cost Estimate

The decommissioning security cost estimate includes the cost of the security modifications, security staffing and the supporting costs for project management and controls. The security modification costs are based on an Engineering, Procurement and Construction (EPC) cost estimate performed by a vendor with security modification experience at DCPP. PG&E labor costs for planning, project management, engineering oversight and permitting were added to the EPC cost estimate. Security staffing labor rates are based on current PG&E or industry standards. Labor costs are in 2017$ and are based on straight time hourly rates.

The total estimated security staffing cost for decommissioning DCPP is $560.7 million. The total security modification cost is $13.2 million.

h. Industry Security Cost Comparisons

Table 4-14 identifies projected staffing levels for DCPP and other decommissioning facilities during similar periods.

TABLE 4-14
DCPP SECURITY STAFFING PROJECTIONS AND INDUSTRY COMPARISONS

Milestone	Period (See Note 1)	DCPP(d) Total Staffing (2 units)	SONGS[b,c] (2 units)	Crystal River 3[a,c] (1 unit)
Pre-shutdown	N/A	272	450	225
Both units defueled, no plant mods, no NRC regulatory approvals	1a	289	360	*
Both units defueled, no plant mods, and NRC regulatory approvals	1b	283	216	*
Both unit(s) defueled, with plant mods, and NRC regulatory approvals	2	207	183	*
Stand-alone ISFSI	3	29	34	50

(a) SAFSTOR plant.
(b) DECON plant.
(c) General ISFSI License.
(d) Specific ISFSI License.
* No data.
Note 1: Period 0 was excluded since the table comparisons do not include a site with one unit shutdown and one unit operational.

The industry comparisons to DCPP security staffing levels in Table 4-14 are illustrative only. Security staffing projections are dependent on several variables, such as site-specific configurations and vulnerabilities, bargaining agreements and state labor laws. Thus, there is no direct correlation between projected DCPP security staffing levels and costs to other decommissioning sites. Several factors affect the DCPP security related cost estimate that are different from other decommissioning sites.

The timing of major security staffing reductions after permanent shutdown was obtained from benchmarking. Typically, the decisions to reduce security staffing were made based upon site-specific milestones. To the extent practical, PG&E mapped the industry data to the DCPP milestones that were reasonably similar to show the relative comparison. Except for Period 3 (stand-alone ISFSI), there is no direct correlation between projected DCPP security staffing levels and the industry comparisons during Periods 1 and 2.

1) Location, Terrain, and Site-Specific Vulnerabilities

The DCPP terrain is more challenging than most U.S. nuclear power plant sites. The DCPP is a dual reactor unit site on approximately 750 acres of land. The plant site occupies a coastal terrace that ranges in elevation from 60’ to 310’ above sea level and is approximately 1,000 ft. wide. Plant grade is at elevation 85’. A portion of the site boundary and principal structures are bounded by the Pacific Ocean. The seaward edge of the terrace is a near-vertical cliff. After permanent shutdown of both units, the proximity of the intake and discharge structure openings to the SFP areas creates additional security challenges to prevent potential adversaries from entering the protected area. Given the size, terrain, and site-specific challenges at the DCPP site, additional security measures and staffing are necessary to meet regulatory requirements.

In comparison, SONGS is a three-unit site on 84 acres of federal land. The SONGS topography is sloping coastal plain that terminates at the shoreline by high sea cliffs. The site is surrounded principally by unused land and the natural exclusion provided by the U.S. Marine Corps reservation. The intake and discharge structure openings are not close to the SFP area. Crystal River is a single-unit site on less than 130 acres. The Crystal River topography is flat and previously disturbed land.

2) Transfer of Spent Fuel and GTCC to DOE

PG&E assumes that DOE would begin picking up DCPP spent fuel in 2038 with full acceptance of all spent fuel and GTCC by 2067. As a result, PG&E assumes security costs are estimated through 2067. In comparison, SONGS and Crystal River DCEs assumed complete transfer of spent fuel to DOE in 2049 and 2036, respectively. Therefore, the DCPP cost estimate includes 16 to 31 additional years of security costs until all spent fuel and GTCC is transferred to DOE. DCPP security staffing costs are approximately $7.0 million/year during dry storage.

3) State of California Labor Laws

California labor laws will result in higher security staffing levels than decommissioning sites in other states with less restrictive labor laws. For example, California law mandates periodic breaks for meals and rest periods, and a recent California Supreme Court decision concluded that security personnel could not be on call during breaks, necessitating separate security coverage.[4] Labor laws for decommissioning sites on federal land (e.g., SONGS) can be less stringent than state labor law requirements.

4) Timing of Permanent Shutdown

Permanent shutdown of the last DCPP operational unit will occur during Period 1. In Period 1, all spent fuel is in the SFP; however, the spent fuel has not sufficiently cooled to ensure the probability of a zirc-fire accident is very low. Some utilities made the decision to permanently shut down near the end of or after the zirc fire window of concern.

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4 *Jennifer Augustus v. ABM Security Services Inc.,* 2 Cal.5th 257 (2016).

For instance, SONGS Units 2 and 3 shutdown in January 2012 due to steam generator-related issues and submitted the certification of permanent shutdown to the NRC in June 2013. Thus, the SONGS to DCPP security staffing comparisons during Period 1 are illustrative only. As a result, SONGS Period 1a staffing levels are higher than the DCPP staffing levels and reflect the security staffing required to meet the pre-shutdown security requirements. The SONGS staffing levels shown for Period 1b reflect the security staffing post- zirc fire accident. During Period 1b, fewer security vulnerabilities existed at SONGS compared to DCPP during the same period. Therefore, the DCPP staffing levels during Period 1b are higher because the staffing levels include the security staffing needed to protect spent fuel before the end of the zirc fire window and relief staff for security posts.

Crystal River shutdown in September 2009 due to containment structural issues and submitted the certification of permanent shutdown to the NRC in February 2013. As a result, the potential risk associated with a zirc fire accident were significantly lower, and fewer security vulnerabilities existed compared to DCPP during the same period.

4. Site infrastructure

Site infrastructure costs are estimated to be $141.0 million. The current estimate reflects a change in scope from the prior estimated site infrastructure costs. Previously, the detail of site infrastructure work was not developed on a project-specific basis. For the 2018 DCE, PG&E determined site infrastructure scope in cooperation with the project planning performed for other scopes of site work. This detailed planning effort identified site infrastructure needs that were not included as part of previous estimates. Major scopes of work in this category include construction of waste handling facilities, construction of an ISFSI security building, upgrades to the rail yard in Pismo Beach, and other modifications. Site infrastructure costs are discussed in DCE Section 4.1.1.2.2.

5. Contingency

Table 4-15 identifies the contingency percentage applied by PG&E for each line item cost category.

TABLE 4-15
CONTINGENCY FACTORS

Line No.	Cost Category	Contingency Factor
1	Program Management, Oversight, and Fees	13.8%
2	Security Operations	15.0%
3	Waste/Transportation/Material Management (Excluding: Breakwater, Reactor Vessel/Internal Segmentation, & Large Component Removal)	29.8%
4	Power Block Modifications	15.0%
5	Site Infrastructure	15.0%
6	Large Component Removal	25.0%
7	Reactor/Internals Segmentation	43.2%
8	Spent Fuel transfer to ISFSI	15.0%
9	Turbine Building	35.9%
10	Auxiliary Building	23.5%
11	Containment	24.1%
12	Fuel Handling Building	24.3%
14	Balance of Site	18.8%
15	Intake Structure	19.8%
16	Discharge Structure	17.7%
17	Breakwater	25.0%
18	Non-ISFSI Site Restoration	19.1%
19	Spent Fuel transfer to DOE	15.0%
20	ISFSI Demolition and Site Restoration	19.6%
21	Grand Total	20.6%

a. Definition of Contingency in Nuclear Decommissioning Context

As the Commission has recognized on several occasions, contingency in the context of forecasting nuclear decommissioning expenditures has a specific meaning: the contingency factor is meant to account for the difference between the base cost and unforeseen, but anticipated, costs.

The base cost estimate defines the project scope and accounts for the known and reasonably anticipated costs of decommissioning in the future. The contingency factor accounts for unforeseen costs within the defined activity scope (i.e., events that will occur in the field during the implementation of the overall decommissioning work period and which are not accounted for in the base cost estimate).

For example, the mechanical failure of heavy equipment, tool breakage, weather delays, and the flooding of a trench are all known unknown events that increase the cost of decommissioning activities. Such cost increases are deemed to be within the scope of the decommissioning project because they occur during the conduct of an activity that is included in the base estimate. At the same time, they are unforeseeable because no one can predict when equipment will break or when the weather will cause delays (causing rescheduling of activities, inefficiencies in production, loss of productivity, overtime, slippages, etc.).

The events covered under contingency are often characterized as the "known unknowns" that will occur over the duration of a decommissioning project. Contingency factors in this sense reflect only one type of risk—the specific risks of increased costs resulting from conditions at the project site after the commencement of the decommissioning work. Contingency dollars provide assurance that sufficient funding is available to accomplish the intended project scope and are expected to be fully expended during decommissioning.

An estimate without contingency, or an inadequate allowance for contingency, can result in significant schedule delays and increased costs associated with delays if the project is unable to proceed. This definition of contingency does not include scope changes, or "unknown unknowns" such as a change in regulatory criteria, significant natural disasters, and security or terrorist activity.

b. Previous Commission Determination as to the Appropriate Level of Contingency

In the 2005 NDCTP, the Commission directed the California utilities to perform a detailed analysis to develop a conservative contingency factor to be applied to each cost estimate and present the findings in the 2009 NDCTP.[5] To comply with the Commission's order, PG&E prepared an analysis titled "Technical Position Paper for Establishing an Appropriate Contingency Factor for Inclusion in the Decommissioning

[5] D.07-01-003, Finding of Fact 9, OP 8.

Revenue Requirements" (Technical Position Paper). Based on industry and regulatory documents, the Technical Position Paper concluded that it is appropriate to apply an overall 25 percent contingency factor to estimated decommissioning costs. Consistent with this recommendation, the Commission found reasonable a 25 percent contingency factor for DCPP in each of PG&E's subsequent NDCTPs.

This determination of the appropriate contingency was made at a time when it was expected that decommissioning would not begin until decades in the future. By the time of the 2012 NDCTP Phase 2 decision, Southern California Edison Company had ceased operations at SONGS 2 & 3, but the Commission continued to determine that a 25 percent contingency factor for SONGS 2 & 3 remained appropriate.

Likewise, in evaluating the SONGS 2 & 3 site-specific DCE proceeding, when SONGS had completed decommissioning conceptual designs and was initiating decommissioning activities, the Commission again approved an overall 25 percent contingency factor.[6]

c. Proposed Contingency for Current DCE

PG&E reevaluated current industry and regulatory guidance since the development of the Technical Position Paper to determine whether the previous conclusion that 25 percent is an appropriate contingency factor for nuclear decommissioning costs remains valid.

The most recent NRC advice states that:

> In general, a contingency of 25 percent applied to the sum of all estimated decommissioning costs should be adequate, but in some cases a higher contingency may be appropriate. The 25 percent contingency factor provides reasonable assurance for unforeseen circumstances that could increase decommissioning costs and should not be reduced or eliminated simply because foreseeable costs are low. Proposals to apply the contingency only to selected components of the cost estimate, or to apply a contingency lower than 25 percent, should be approved only in circumstances when a case-specific review has determined there is an extremely low likelihood of unforeseen increases in the decommissioning costs

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6 D.16-04-019.

(e.g., if the decommissioning costs are highly predictable and are established by binding contracts.)[7]

As it has in previous NDCTP filings, PG&E has calculated contingency at the line item level. However, PG&E has not adjusted the overall contingency to 25 percent as the Commission approved in prior NDCTP decisions. The overall line item contingency rate based on the site specific DCE is 20.6 percent. PG&E believes that this contingency level is appropriate given the current early stage of decommissioning. PG&E will continue to assess applicable project contingency levels in future NDCTPs.

6. Environmental Reviews/Permits

PG&E will require many regulatory approvals and permits to decommission DCPP which will require close coordination with federal, state, and local agencies. Delays in obtaining (or failure to obtain) approval and/or possible regulatory conditions could significantly impact estimated costs.

As an illustrative example how failure to obtain agency approvals could have a major effect on estimated costs, DCE Section 3.1.6. explains how PG&E's cost estimate for its water management plan relies on the assumptions that: (1) PG&E will obtain an extension of its lease from the CSLC to continue use of the intake cove and discharge structure for drawing in ocean water and discharging waste water to the ocean; and (2) PG&E will obtain a National Pollutant Discharge Elimination System permit to allow for discharges of waste water to the Pacific Ocean during decommissioning.

With these assumptions, the water management plan uses a combination of existing site infrastructure and temporary equipment to continue provide a supply of ocean water to the desalination plant for fresh water supply and to dispose of waste water to an approved discharge point. In their absence, PG&E would lack access to the Pacific Ocean and would need to develop other water use options. The options that could be

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7 U.S. Nuclear Regulatory Commission Regulation (NUREG)-1757, Consolidated Decommissioning Guidance Financial Assurance, Recordkeeping, and Timeliness, Vol. 3, Rev. 1 dated February 2012 at A.3.2.1.3.

considered include the use of trucks; the installation of additional water wells; and the installation of pipelines to tie into local water.

F. Schedule

A summary DCPP decommissioning schedule is presented in Figures 4-F and 4-G.

1. Schedule Assumptions

The following assumptions were made in developing the schedule:

- Detailed decommissioning planning will begin in 2019.
- Permanent shutdown for Units 1 and 2 is November 2024 and August 2025, respectively.
- SNF and GTCC waste will be moved to ISFSI within seven years after Unit 2 shutdown.
- The SFP zirconium fire period will end 18 months after each unit shutdown.
- Major building demolition will not occur until after the main power block PA is devitalized and security requirements are relaxed.
- The Part 50 licenses will be terminated in May 2038.
- All SNF and GTCC waste will be removed from DC ISFSI by August 2067.
- The Part 72 site-specific license will be terminated in May 2072.
- All work (except cask transfer activities) will be performed during a 10-hour workday, four days per week (termed a 4x10 work schedule), with no overtime.
- Activities that do not follow a 4x10 work schedule will be performed with separate crews working on different shifts with a corresponding charge for the second shift.
- The schedule is optimized to allow multiple crews to work parallel activities to the maximum extent possible allowing for: (1) access to various site facilities to execute work; (2) removal and/or staging areas; and (3) safety measures required to ensure safe efficient decommissioning of the site’s equipment, components, and structures.

- Critical path is determined based on the systems and scopes of work in the Decommissioning Project. Delay of any part of the critical path will delay the overall project completion date.

The DCPP decommissioning schedule was developed by vendors with industry expertise in nuclear decommissioning and by personnel with direct experience with HBPP decommissioning. As a result, the schedule incorporates best practices and lessons learned from several sites that have undergone or are undergoing decommissioning.

2. Critical Path Activities

Schedule activity durations were established between milestones for each subproject; these durations were used to establish a critical path (minimum time needed) for the entire Decommissioning Project. Critical path activities and bottlenecks/constraints were determined for those items that highly influence the schedule and are shown in Figures 4-F and 4-G. These activities include:

- **Units 1 and 2 spent fuel cooling window**: Cooling time reduces the heat load of spent fuel assemblies. The initial critical path cooling window activity duration extends approximately seven years after Unit 2 shut down (see DCE Section 3.5. for further discussion). The spent fuel is cooled in the SFPs until heat loads are low enough to transfer to dry cask storage in accordance with the DC ISFSI license from the NRC.
- **Units 1 and 2 spent fuel and GTCC waste transfer to the DC ISFSI:** While the SFPs are being used to store spent fuel or GTCC waste, systems and structures that support the SFPs’ operation cannot be demolished. Once transfer to the DC ISFSI is complete, several work activities may begin.
- **Units 1 and 2 Reactor Pressure Vessel and Internals Segmentation, Packaging and Disposal:** Removal and disposal of the Reactor Pressure Vessel (RPV) and internals has typically been performed long after final reactor shutdown which allows for substantial radioactive decay of the irradiated materials. In addition, many of the previously segmented reactors had poor operational performance or unexpectedly ceased operation early in life, resulting in considerably lower levels of radiation as compared to that which will be present in the DCPP RPVs

and internals when Units 1 and 2 stop operating in 2024 and 2025, respectively. Put another way, total radionuclide concentrations in the DCPP RPV and internals will be significantly higher than any that have been encountered during previous segmentation activities at other plants. To address this unique challenge, a team of subject matter experts with vast decommissioning experience developed a comprehensive segmentation plan and schedule drawing from actual experience obtained from previously executed RPV and internals segmentation projects. The plan addresses the health and safety risks posed by the inherent danger and complexity of this work, and is based on site specific design characteristics, operating parameters, and materials of construction for the DCPP Units 1 and 2 RPVs and internals.

Due to close proximity to the nuclear fuel, the RPV and internals become highly radioactive, and the radionuclide concentrations estimated to be present at end of operation result in extremely high levels of radiation emanating from the materials. To develop a basis for the radionuclide isotopes and concentrations that will be present within the RPVs and internals at the time of final shutdown for Units 1 and 2, a unit-specific waste characterization analysis was performed by consultants with experience and expertise in the area of RPV and internals segmentation and disposal. Based on results of the waste characterization analysis, segmentation and packaging plans that meet NRC and DOT regulation limits for transporting and disposing of radioactive waste were developed for both Units 1 and 2. Since the cost to dispose of Class A waste is significantly less than Class B or Class C waste, the plans ensure the quantity of waste that will be disposed of as Class A is maximized.

Results of the waste characterization analysis support the determination that the optimal time to begin RPV and internals segmentation and packaging is approximately five years after shutdown. This allows time for adequate radioactive decay of short-lived gamma-emitting radionuclides, which will reduce accumulation of worker dose; allow for immediate transportation of waste to licensed off-site waste disposal facilities; optimize RPV and internals segmentation duration by allowing for larger individual pieces; and support timely reduction in security staffing requirements for areas beyond the ISFSI pad, as described in DCE, Section 3.4.3.3., by ensuring the reactor internals waste classified as GTCC is removed from the Containment Buildings and placed for storage on the ISFSI pad no later than seven years after Unit 2 is shut down.

To minimize the total schedule duration for Units 1 and 2 RPV and internals segmentation activities, segmentation of the Unit 2 RPV and internals will be performed concurrent with completion of the Unit 1 RPV and internals segmentation activities. The start of activities associated with Unit 2 are labor resource dependent following a period of operating experience obtained from operations within Unit 1. This results in an offset of approximately seven months between the start of segmentation operations between Units 1 and 2. To support parallel segmentation activities for both Units 1 and 2, two complete sets of RPV and internals segmentation equipment will be provided. The total duration for both units, with Unit 2 work in parallel commencing seven months after Unit 1 start is approximately 56 months.

- **Unit 2 Containment Building Interior Demolition:**[8] Due to As Low As Reasonably Achievable (ALARA) and safety concerns, the containment building interior demolition work cannot take place until: (1) the spent fuel and GTCC waste are removed from the SFP, and (2) the last of the major components (i.e., RPV and reactor vessel internals (RVI) as described above) are removed.
- **Unit 2 Auxiliary Building and Fuel Handling Building (FHB) Demolitions:** The Auxiliary Building and FHB demolitions cannot take place until the spent fuel and GTCC waste are removed from the SFP.
- **Unit 2 Containment Building Demolition:** Due to ALARA and safety concerns, this containment building exterior demolition work cannot take

[8] It should be noted that demolitions of the Unit 1 Containment Building, Auxiliary Building, and FHB are not considered critical path because the Unit 1 RPV/RVI segmentations and removals complete five months before Unit 2 RPV/RVI segmentations start. This five-month lead allows the Unit 1 demolitions to start sooner than Unit 2; thus, making it non-critical path.

place until: (1) the spent fuel and GTCC waste are removed from the SFP, and (2) the interior has been demolished.

- **Radioactive Waste Processing Facility:** The formerly titled Warehouse Building, Building 115, is being repurposed as the Radioactive Waste Processing Facility. It cannot be demolished until all other buildings and structures with radioactive waste have been demolished.
- **Breakwaters Demolition:** Breakwater removal is scheduled late in the project to allow the breakwater structure to maintain a calm water supply suction location for plant demolition water needs, as stated in DCE Section 3.1.6.1., and to distribute waste stream volumes across the project so as to not overcome the capability of transferring waste offsite. This also allows for FSSs to be completed while the Breakwaters are being removed. Earlier removal of the breakwater will require identification of an alternate water supply path and will challenge offsite waste transportation activities.
- **Final Landscaping, Re-vegetation, and Demobilization:** This is the last activity to be completed for non-ISFSI decommissioning. Because overhead costs can be reduced or eliminated once this activity is completed, it is imperative to the budget that it be finished as soon as possible.
- **Spent Fuel and GTCC Waste Transfer From the ISFSI to a Permanent Offsite Facility:** Transfer to a permanent offsite facility cannot begin until all spent fuel and GTCC waste has been moved from the SFPs to the ISFSI and the offsite facility is ready to accept the spent fuel and GTCC waste (see DCE Section 3.5.8.).
- **ISFSI Demolition Activities:** The ISFSI demolition cannot begin until all spent fuel and GTCC waste have been transferred to the DOE. The critical path activities related to ISFSI demolition include mobilizing/demobilizing contractors; removing utilities, ancillary roads, fences, barriers, and the ISFSI pad; performing soil remediation; backfilling, grading, and landscaping; establishing erosion control; and revegetation.

It is important to track critical path activities as they can put the remainder of the schedule at-risk. For example, if the spent fuel and GTCC waste are not transferred to the DC ISFSI as-scheduled, then building demolition cannot be completed, and the licenses cannot be terminated. In addition, although not initially determined to be a critical path activity, an activity may become critical path as new information is identified during the detailed planning efforts or project execution. For instance, new critical path activities may be identified if existing critical path activities are completed significantly earlier, significantly delayed, or if there is a change to the order of work activities.

3. Alternatives Considered

In developing the schedule, several options were considered to minimize the critical path activities such as conducting work in parallel and completing planning work before physical work begins. Facets of these options were incorporated into the schedule as follows:

- RPV and RVI segmentation were originally scheduled to occur in a series (segmentation starts at the second unit after it's completed at the first unit). Adding additional equipment and personnel so that segmentation could be completed in parallel for both units as much as possible reduced the time to do this by 13 months. That savings in overhead costs more than offsets the added cost for additional equipment and personnel.
- The feasibility of commencing segmentation and disposal of the RPV and internals at approximately two years following final reactor shutdown was evaluated by decay correcting the results of the waste characterization analysis and drafting representative segmentation and packaging plans. To ensure the ability to transport the loaded waste containers beginning approximately two years following shutdown of the units, the segmentation and packaging plans were developed based on the capacity and radioactivity limitations of the NRC licensed TN-RAM Type B transportation cask. The capacity and radioactivity limitations of the cask necessitate exorbitant time and effort to segment the RPV and internals into sizes sufficiently small to fit within the cask, ultimately requiring the use of greater than 100 waste containers and Type B

waste shipments per unit. This was contrary to goal of minimizing the amount of time required to segment the RPV and internals and minimizing the number of waste shipments requiring the use of a NRC licensed Type B transportation cask. Therefore, commencing segmentation and disposal of the RPV and internals at approximately two years following final reactor shutdown was deemed unreasonable.

- The time spent for: (1) spent fuel and GTCC waste transfer to the ISFSI and (2) RPV and RVI segmentation and disposal were optimized to allow for as many parallel activities as possible. By incorporating parallel work, critical path building demolition (i.e., Containment Buildings, Auxiliary Building, and FHBs) can begin as soon as possible.
- Planning, licensing, and permitting efforts were originally scheduled to occur after both units are permanently shut down. However, to save time and money, they are scheduled to be completed prior to permanent shutdown.

G. Conclusion

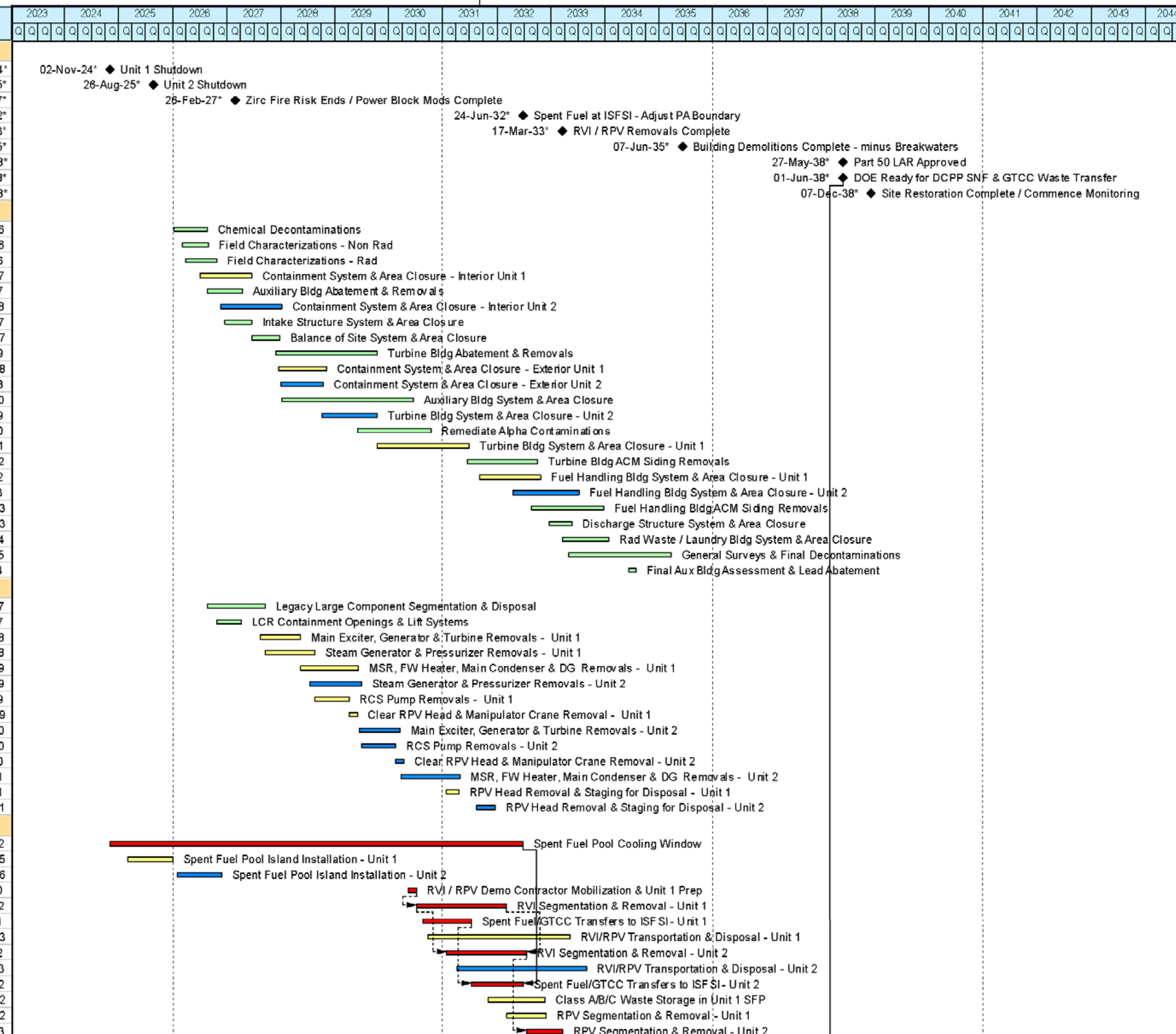
The Commission should adopt PG&E’s estimate to decommission DCPP of $4,802.4 million.

FIGURE 4-F
DCPP DEMOLITION AND SITE RESTORATION SCHEDULE

DCPP Decommissioning Summary Schedule

Unit 2 Shutdown to License Termination = 12 years, 9 months (approx)
Based on Field Work Only and Excludes ISFSI Restoration

#	Activity Name	Dur in Months	Start	Finish
1	***1) Milestones***			
2	Unit 1 Shutdown	0		02-Nov-24*
3	Unit 2 Shutdown	0		26-Aug-25*
4	Zirc Fire Risk Ends / Power Block Mods Complete	0		26-Feb-27*
5	Spent Fuel at ISFSI - Adjust PA Boundary	0		24-Jun-32*
6	RVI / RPV Removals Complete	0		17-Mar-33*
7	Building Demolitions Complete - minus Breakwaters	0		07-Jun-35*
8	Part 50 LAR Approved	0		27-May-38*
9	DOE Ready for DCPP SNF & GTCC Waste Transfer	0		01-Jun-38*
10	Site Restoration Complete / Commence Monitoring	0		07-Dec-38*
11	***2) Decontamination & System/Area Closures***			
12	Chemical Decontaminations	7	08-Jan-26	19-Aug-26
13	Field Characterizations - Non Rad	6	09-Mar-26	31-Aug-26
14	Field Characterizations - Rad	7	31-Mar-26	26-Oct-26
15	Containment System & Area Closure - Interior Unit 1	12	02-Jul-26	21-Jun-27
16	Auxiliary Bldg Abatement & Removals	8	20-Aug-26	15-Apr-27
17	Containment System & Area Closure - Interior Unit 2	13	25-Nov-26	05-Jan-28
18	Intake Structure System & Area Closure	6	23-Dec-26	22-Jun-27
19	Balance of Site System & Area Closure	6	17-Jun-27	22-Dec-27
20	Turbine Bldg Abatement & Removals	22	01-Dec-27	11-Oct-29
21	Containment System & Area Closure - Exterior Unit 1	10	20-Dec-27	01-Nov-28
22	Containment System & Area Closure - Exterior Unit 2	10	30-Dec-27	16-Oct-28
23	Auxiliary Bldg System & Area Closure	29	06-Jan-28	18-Jun-30
24	Turbine Bldg System & Area Closure - Unit 2	12	11-Oct-28	11-Oct-29
25	Remediate Alpha Contaminations	16	31-May-29	09-Oct-30
26	Turbine Bldg System & Area Closure - Unit 1	20	15-Oct-29	30-Jun-31
27	Turbine Bldg ACM Siding Removals	15	17-Jun-31	30-Sep-32
28	Fuel Handling Bldg System & Area Closure - Unit 1	13	10-Sep-31	21-Oct-32
29	Fuel Handling Bldg System & Area Closure - Unit 2	15	20-Apr-32	07-Jul-33
30	Fuel Handling Bldg ACM Siding Removals	16	24-Aug-32	27-Dec-33
31	Discharge Structure System & Area Closure	5	20-Dec-32	24-May-33
32	Rad Waste / Laundry Bldg System & Area Closure	10	21-Mar-33	25-Jan-34
33	General Surveys & Final Decontaminations	23	28-Apr-33	21-Mar-35
34	Final Aux Bldg Assessment & Lead Abatement	1	14-Jun-34	26-Jul-34
35	***3) Large Component Removals***			
36	Legacy Large Component Segmentation & Disposal	13	20-Aug-26	15-Sep-27
37	LCR Containment Openings & Lift Systems	6	26-Oct-26	13-Apr-27
38	Main Exciter, Generator & Turbine Removals - Unit 1	9	16-Aug-27	11-May-28
39	Steam Generator & Pressurizer Removals - Unit 1	11	20-Sep-27	17-Aug-28
40	MSR, FW Heater, Main Condenser & DG Removals - Unit 1	13	16-May-28	12-Jun-29
41	Steam Generator & Pressurizer Removals - Unit 2	12	13-Jul-28	28-Jun-29
42	RCS Pump Removals - Unit 1	7	21-Aug-28	04-Apr-29
43	Clear RPV Head & Manipulator Crane Removal - Unit 1	2	05-Apr-29	30-May-29
44	Main Exciter, Generator & Turbine Removals - Unit 2	9	14-Jun-29	19-Mar-30
45	RCS Pump Removals - Unit 2	7	02-Jul-29	14-Feb-30
46	Clear RPV Head & Manipulator Crane Removal - Unit 2	2	19-Feb-30	11-Apr-30
47	MSR, FW Heater, Main Condenser & DG Removals - Unit 2	13	21-Mar-30	24-Apr-31
48	RPV Head Removal & Staging for Disposal - Unit 1	3	29-Jan-31	17-Apr-31
49	RPV Head Removal & Staging for Disposal - Unit 2	4	19-Aug-31	23-Dec-31
50	***4) Spent Fuel Transfers & Reactor Segmentations***			
51	Spent Fuel Pool Cooling Window	92	02-Nov-24*	24-Jun-32
52	Spent Fuel Pool Island Installation - Unit 1	10	03-Mar-25	31-Dec-25
53	Spent Fuel Pool Island Installation - Unit 2	10	02-Feb-26	25-Nov-26
54	RVI / RPV Demo Contractor Mobilization & Unit 1 Prep	2	13-May-30	07-Jul-30
55	RVI Segmentation & Removal - Unit 1	20	08-Jul-30	04-Mar-32
56	Spent Fuel/GTCC Transfers to ISFSI - Unit 1	11	19-Aug-30	11-Jul-31
57	RVI/RPV Transportation & Disposal - Unit 1	31	24-Sep-30	05-May-33
58	RVI Segmentation & Removal - Unit 2	18	27-Jan-31	15-Jul-32
59	RVI/RPV Transportation & Disposal - Unit 2	29	09-Apr-31	29-Aug-33
60	Spent Fuel/GTCC Transfers to ISFSI - Unit 2	11	14-Jul-31	24-Jun-32
61	Class A/B/C Waste Storage in Unit 1 SFP	13	04-Nov-31	23-Nov-32
62	RPV Segmentation & Removal - Unit 1	9	08-Mar-32	30-Nov-32
63	RPV Segmentation & Removal - Unit 2	8	19-Jul-32	17-Mar-33



Legend Unit 1 · Unit 2 · Common · Critical · ◆ Milestone

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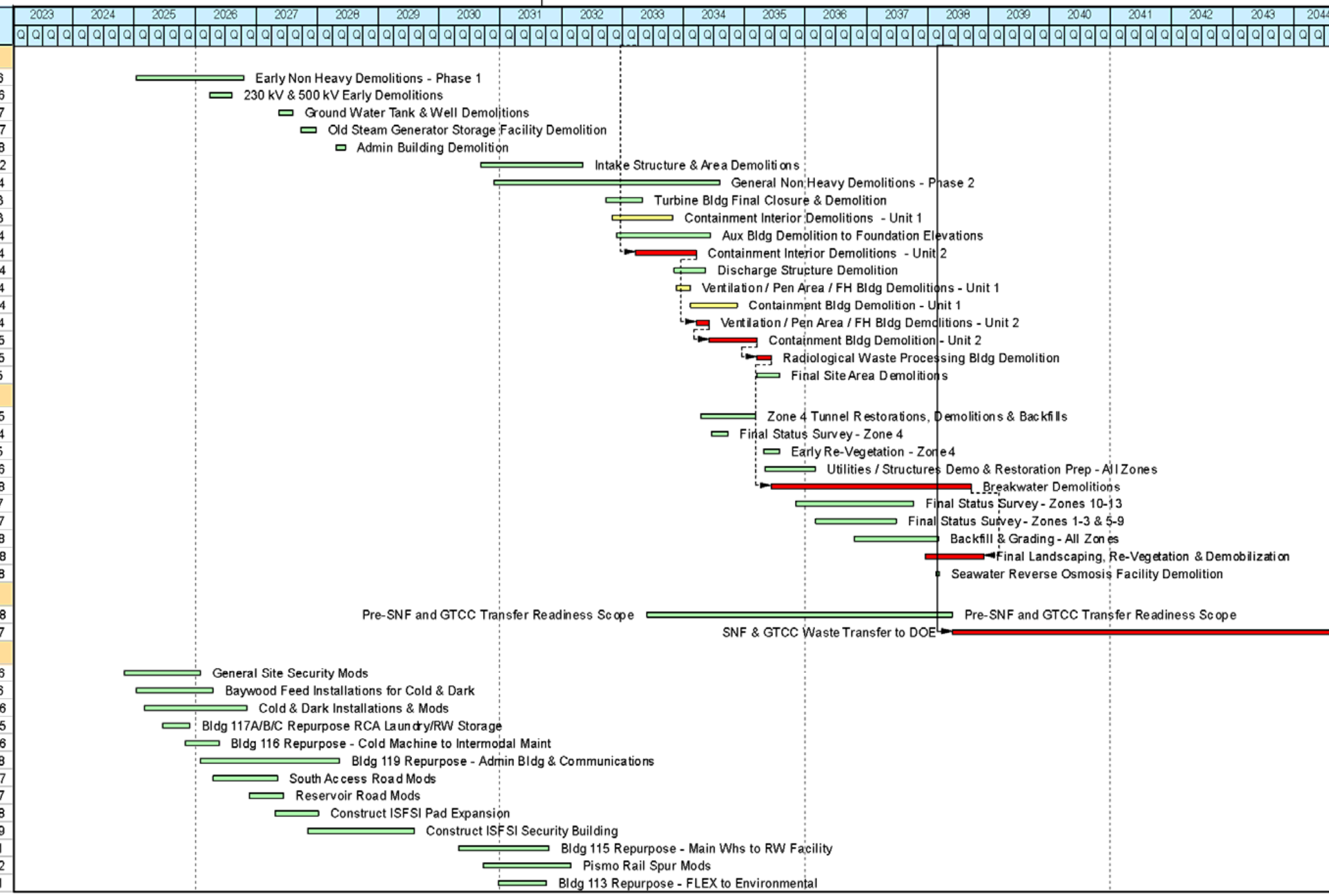
FIGURE 4-F
DCPP DEMOLITION AND SITE RESTORATION SCHEDULE
(CONTINUED)

DCPP Decommissioning Summary Schedule

Unit 2 Shutdown to License Termination = 12 years, 9 months (approx)
Based on Field Work Only and Excludes ISFSI Restoration

#	Activity Name	Dur in Months	Start	Finish
64	***5) Building & Structural Demolitions***			
65	Early Non Heavy Demolitions - Phase 1	21	13-Jan-25	14-Oct-26
66	230 kV & 500 kV Early Demolitions	4	26-Mar-26	05-Aug-26
67	Ground Water Tank & Well Demolitions	3	17-May-27	10-Aug-27
68	Old Steam Generator Storage Facility Demolition	3	23-Sep-27	22-Dec-27
69	Admin Building Demolition	2	24-Apr-28	19-Jun-28
70	Intake Structure & Area Demolitions	20	10-Sep-30	06-May-32
71	General Non Heavy Demolitions - Phase 2	45	21-Nov-30	07-Aug-34
72	Turbine Bldg Final Closure & Demolition	7	27-Sep-32	27-Apr-33
73	Containment Interior Demolitions - Unit 1	12	01-Nov-32	26-Oct-33
74	Aux Bldg Demolition to Foundation Elevations	18	29-Nov-32	13-Jun-34
75	Containment Interior Demolitions - Unit 2	12	21-Mar-33	15-Mar-34
76	Discharge Structure Demolition	6	09-Nov-33	16-May-34
77	Ventilation / Pen Area / FH Bldg Demolitions - Unit 1	3	17-Nov-33	13-Feb-34
78	Containment Bldg Demolition - Unit 1	9	14-Feb-34	15-Nov-34
79	Ventilation / Pen Area / FH Bldg Demolitions - Unit 2	3	16-Mar-34	06-Jun-34
80	Containment Bldg Demolition - Unit 2	9	07-Jun-34	14-Mar-35
81	Radiological Waste Processing Bldg Demolition	3	15-Mar-35	07-Jun-35
82	Final Site Area Demolitions	5	15-Mar-35	31-Jul-35
83	***6) Site Surveys & Restorations***			
84	Zone 4 Tunnel Restorations, Demolitions & Backfills	11	19-Apr-34	07-Mar-35
85	Final Status Survey - Zone 4	3	21-Jun-34	25-Sep-34
86	Early Re-Vegetation - Zone 4	3	01-May-35	30-Jul-35
87	Utilities / Structures Demo & Restoration Prep - All Zones	10	09-May-35	28-Feb-36
88	Breakwater Demolitions	39	11-Jun-35	21-Sep-38
89	Final Status Survey - Zones 10-13	23	07-Nov-35	13-Oct-37
90	Final Status Survey - Zones 1-3 & 5-9	16	03-Mar-36	25-Jun-37
91	Backfill & Grading - All Zones	16	20-Oct-36	03-Mar-38
92	Final Landscaping, Re-Vegetation & Demobilization	12	22-Dec-37	07-Dec-38
93	Seawater Reverse Osmosis Facility Demolition	1	22-Feb-38	11-Mar-38
94	***7) SNF and GTCC Waste Transfer to Off-Site Facility***			
95	Pre-SNF and GTCC Transfer Readiness Scope	58	01-Jun-33	27-May-38
96	SNF & GTCC Waste Transfer to DOE	338	01-Jun-38	01-Aug-67
97	***8) Infrastructure & Support Projects***			
98	General Site Security Mods	15	04-Nov-24	02-Feb-26
99	Baywood Feed Installations for Cold & Dark	15	15-Jan-25	16-Apr-26
100	Cold & Dark Installations & Mods	20	27-Feb-25	05-Nov-26
101	Bldg 117A/B/C Repurpose RCA Laundry/RW Storage	5	23-Jun-25	26-Nov-25
102	Bldg 116 Repurpose - Cold Machine to Intermodal Maint	7	03-Nov-25	20-May-26
103	Bldg 119 Repurpose - Admin Bldg & Communications	27	02-Feb-26	11-May-28
104	South Access Road Mods	12	22-Apr-26	06-May-27
105	Reservoir Road Mods	7	24-Nov-26	10-Jun-27
106	Construct ISFSI Pad Expansion	9	22-Apr-27	06-Jan-28
107	Construct ISFSI Security Building	21	04-Nov-27	07-Aug-29
108	Bldg 115 Repurpose - Main Whs to RW Facility	18	01-May-30	15-Oct-31
109	Pismo Rail Spur Mods	17	25-Sep-30	02-Mar-32
110	Bldg 113 Repurpose - FLEX to Environmental	9	23-Dec-30	01-Oct-31



Legend Unit 1 Unit 2 Common Critical ◆ Milestone

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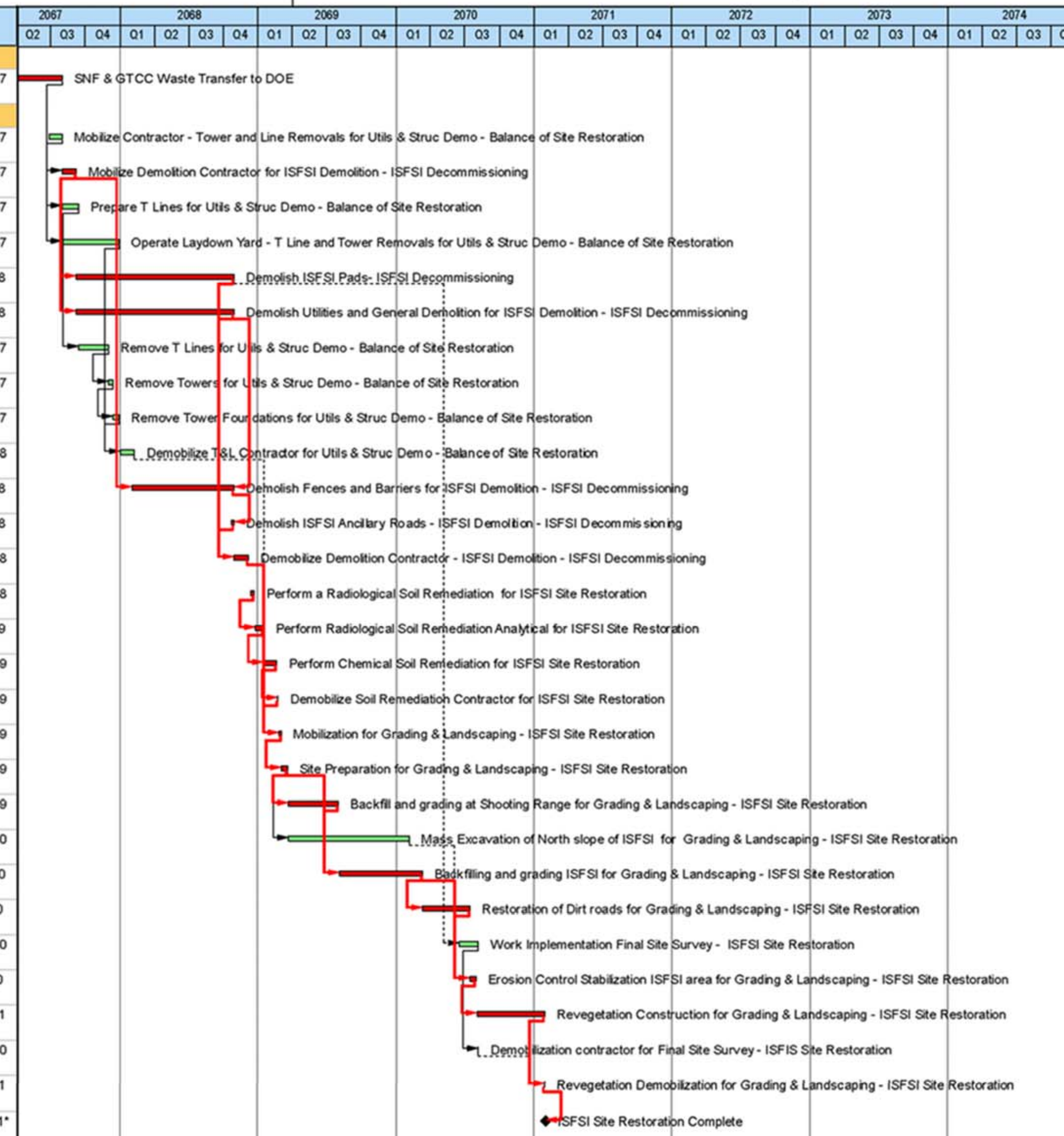
FIGURE 4-G
ISFSI DEMOLITION AND ISFSI SITE RESTORATION SCHEDULE

ISFSI Restoration Schedule

ISFSI Site Restoration Duration = 3 years, 6 months
Excludes Follow-on Monitoring

#	Activity Name	Dur in Months	Start	Finish
1	***1) GTCC and Spent Nuclear Fuel Waste Transfer to DOE***			
2	SNF & GTCC Waste Transfer to DOE	338	01-Jun-38	01-Aug-67
3	***2) ISFSI Site Restoration***			
4	Mobilize Contractor - Tower and Line Removals for Utils & Struc Demo - Balance of Site Restoration	1	27-Jun-67	01-Aug-67
5	Mobilize Demolition Contractor for ISFSI Demolition - ISFSI Decommissioning	1	02-Aug-67	06-Sep-67
6	Prepare T Lines for Utils & Struc Demo - Balance of Site Restoration	1	02-Aug-67	14-Sep-67
7	Operate Laydown Yard - T Line and Tower Removals for Utils & Struc Demo - Balance of Site Restoration	5	02-Aug-67	29-Dec-67
8	Demolish ISFSI Pads- ISFSI Decommissioning	13	07-Sep-67	29-Oct-68
9	Demolish Utilities and General Demolition for ISFSI Demolition - ISFSI Decommissioning	13	07-Sep-67	29-Oct-68
10	Remove T Lines for Utils & Struc Demo - Balance of Site Restoration	2	15-Sep-67	30-Nov-67
11	Remove Towers for Utils & Struc Demo - Balance of Site Restoration	0	01-Dec-67	13-Dec-67
12	Remove Tower Foundations for Utils & Struc Demo - Balance of Site Restoration	1	14-Dec-67	29-Dec-67
13	Demobilize T&L Contractor for Utils & Struc Demo - Balance of Site Restoration	1	03-Jan-68	07-Feb-68
14	Demolish Fences and Barriers for ISFSI Demolition - ISFSI Decommissioning	9	02-Feb-68	29-Oct-68
15	Demolish ISFSI Ancillary Roads - ISFSI Demolition - ISFSI Decommissioning	0	22-Oct-68	29-Oct-68
16	Demobilize Demolition Contractor - ISFSI Demolition - ISFSI Decommissioning	1	30-Oct-68	05-Dec-68
17	Perform a Radiological Soil Remediation for ISFSI Site Restoration	0	13-Dec-68	20-Dec-68
18	Perform Radiological Soil Remediation Analytical for ISFSI Site Restoration	1	26-Dec-68	14-Jan-69
19	Perform Chemical Soil Remediation for ISFSI Site Restoration	1	15-Jan-69	20-Feb-69
20	Demobilize Soil Remediation Contractor for ISFSI Site Restoration	0	21-Feb-69	21-Feb-69
21	Mobilization for Grading & Landscaping - ISFSI Site Restoration	0	25-Feb-69	04-Mar-69
22	Site Preparation for Grading & Landscaping - ISFSI Site Restoration	1	05-Mar-69	20-Mar-69
23	Backfill and grading at Shooting Range for Grading & Landscaping - ISFSI Site Restoration	4	21-Mar-69	01-Aug-69
24	Mass Excavation of North slope of ISFSI for Grading & Landscaping - ISFSI Site Restoration	10	21-Mar-69	04-Feb-70
25	Backfilling and grading ISFSI for Grading & Landscaping - ISFSI Site Restoration	7	05-Aug-69	11-Mar-70
26	Restoration of Dirt roads for Grading & Landscaping - ISFSI Site Restoration	4	12-Mar-70	14-Jul-70
27	Work Implementation Final Site Survey - ISFSI Site Restoration	2	18-Jun-70	05-Aug-70
28	Erosion Control Stabilization ISFSI area for Grading & Landscaping - ISFSI Site Restoration	1	15-Jul-70	31-Jul-70
29	Revegetation Construction for Grading & Landscaping - ISFSI Site Restoration	6	04-Aug-70	28-Jan-71
30	Demobilization contractor for Final Site Survey - ISFIS Site Restoration	0	06-Aug-70	06-Aug-70
31	Revegetation Demobilization for Grading & Landscaping - ISFSI Site Restoration	0	29-Jan-71	29-Jan-71
32	ISFSI Site Restoration Complete	0		02-Feb-71*



Legend Common Critical ◆ Milestone

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

DIABLO CANYON POWER PLANT LANDS

AND RELATED MATTERS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
DIABLO CANYON POWER PLANT LANDS
AND RELATED MATTERS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
DIABLO CANYON POWER PLANT LANDS AND RELATED MATTERS

A. Introduction

The purpose of this chapter is to describe Diablo Canyon Power Plant (DCPP or Diablo Canyon) lands and land ownership; provide an update on the activities and status of the public stakeholder process ordered by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 18-01-022; provide preliminary information about ideas developed through the public stakeholder process for repurposing the breakwaters and use of DCPP lands after decommissioning is completed; provide a status on Pacific Gas and Electric Company's (PG&E or the Company) discussions with state agencies regarding the disposition of the breakwaters and Executive Order (EO) D-62-02; and provide information necessary to comply with the Commission's directive that PG&E identify all environmental permits necessary to decommission DCPP Units 1 and 2.

B. DCPP Lands

The lands around DCPP are owned by two entities—either PG&E, or Eureka Energy Company (Eureka), which is a wholly-owned subsidiary of PG&E. There are approximately 12,800 acres that make up this area and are known generally in the public and in San Luis Obispo County Planning parlance as the "Diablo Properties," though not all the parcels are contiguous. Much of the Diablo Properties are subject to leases held by other parties and there are other encumbrances, such as public access trails and deed restrictions arising from various Coastal Development Permits (CDP) that restrict the use of the Diablo Properties. There are three land use categories under the San Luis Obispo General Plan, Framework for Planning, that apply to the Diablo Properties. Most of the parcels are zoned for agriculture or rural lands use by the County of San Luis Obispo, which has land use jurisdiction over the properties. Only the parcels of land where DCPP resides have a different zoning use, which is public facilities, that allows for such uses as power plants.

Approximately 4,000 of the 12,800 acres of the Diablo Properties are also in the coastal zone and are subject to the jurisdiction of the California Coastal Commission (CCC or Coastal Commission) in addition to the County of San Luis Obispo's approved Local Coastal Program.

As a general matter, PG&E's land acquisition strategy for the Diablo Properties has been to build a large buffer zone surrounding DCPP to facilitate and secure plant operations and access. As additional parcels or land interests have become available, often through bankruptcy or other court proceedings, PG&E has acquired additional land interests to expand the DCPP buffer zone and to secure access to DCPP.

Many of the original land interests acquired by PG&E for the DCPP footprint were long-term lease interests. As the fee interests in these properties later became available, Eureka often acquired these interests in order to preserve the original leasehold structure. The objective of these acquisitions was to facilitate utility operations and access to DCPP, and to mitigate the risk of third-party land uses conflicting with or being inconsistent with the safety, access and power production objectives at DCPP. Today, the land interests owned or controlled by PG&E and/or Eureka are managed under the Company's Land Stewardship Program. A map showing all lands adjacent or contiguous to DCPP owned or leased by PG&E, or any affiliates or subsidiaries and identifying ownership of the lands and other property rights in the lands and total acreage is presented in Attachment A.

1. PG&E Affiliates or Subsidiaries That Hold Property Rights in Any of the Lands

Eureka is a California corporation and a wholly-owned subsidiary of PG&E. Its date of formation is September 22, 1978. Eureka is the owner and lessor of the parcels highlighted in green on the map provided in Attachment A and performs no other business activity.

2. Property or Contractual Rights in the Lands Held by Third Parties, Such as Leases, Easements or Options

a. Pecho Coast Trail

In 1983, PG&E obtained a CDP in connection with the training/simulator building project. The CDP required PG&E to establish a lateral shoreline and bluff top hiking access trail on the South Ranch, known as the Pecho Coast Trail. PG&E manages the Pecho Coast Trail in accordance with an Accessway Management Plan approved by the Coastal Commission.

b. Land Transactions with the Port San Luis Harbor District

In 2006, PG&E obtained a CDP in connection with PG&E's Steam Generator Replacement Project. The CDP required, as conditions of approval, that PG&E enter into certain land transactions with the Port San Luis Harbor District and place a deed restriction on 1,200 acres of property on the South Ranch. The land transactions with the Port included the conveyance of a road easement to access the historic Port San Luis Lighthouse, the conveyance of 11.72 acres of land (which included 6.24 acres of land under the Properties lease described in more detail in Section C.3. below), and a construction access and drainage easement. PG&E obtained the CPUC's approval of these land transactions in Advice Letter (AL) 4235-E with the effective date of July 5, 2013. PG&E is currently working with the Coastal Commission staff on the form of the deed restriction on the 1,200 acres.

c. Point Buchon Deed Restriction

In 2004, PG&E obtained a CDP in connection with PG&E's Independent Spent Fuel Storage Installation Project. The CDP required, as conditions of approval, that PG&E place a deed restriction on property on the North Ranch for a public use trail and associated public viewing areas along the North Ranch Property. PG&E obtained the Commission's approval of this deed restriction in AL 3630-E with the effective date of June 11, 2010. PG&E is currently working with the Coastal Commission staff on the form of the deed restriction for the Point Buchon Trail.

d. Pre-Existing Encumbrances to Eureka Energy Company's Fee Title

At the time Eureka acquired fee title in 1995, there were several existing road and utility easements encumbering the property. These pre-existing encumbrances are summarized below:

(1) An easement for road and incidental purposes granted to Ramona W. Willard and recorded October 15, 1892, in Book 17 of Deeds, Page 437. This easement affects a portion of Rancho San Miguelito.

(2) An easement for pole line, ingress, egress and incidental purposes granted to Sunset Telephone and Telegraph Company and recorded November 11, 1903 in Book 62 of Deeds, Page 136.

(3) An easement for pipe lines and incidental purposes in favor of Union Oil Company of California and recorded February 1, 1906 in Book 69 of Deeds, Page 22.

(4) An easement for road and incidental purposes for the exclusive use of the U.S. Coast Guard and recorded October 10, 1962, as Book 1205 Page 561 of Official Records.

(5) An easement for electrical facilities and incidental purposes granted to PG&E and recorded May 28, 1969, as Book 1519 Page 7 of Official Records.

(6) An easement for access, ingress, egress and incidental purposes granted to James Talcott, Inc. and recorded April 3, 1978, as Book 2059 Page 615 of Official Record.

(7) An easement for communication facilities and incidental purposes granted to Pacific Telephone and Telegraph Company and recorded June 20, 1979, as Book 2164 Page 480 of Official Records.

3. Other Third Party Uses

On March 6, 2008, Eureka granted a road easement to Robert Rolla Martin, Trustee of the Robert Rolla Martin Living Trust Dated December 16, 1996, for ingress and egress to Martin's adjoining property. The grant of easement was the result of a settlement of an action brought in San Luis Obispo County Superior Court and is recorded on September 8, 2008, as Instrument No. 2008045979.

On March 20, 2017, PG&E issued a license for grazing and agricultural purposes to Frank Mello, Jr. This license expires September 30, 2021, but may be renewed.

On June 16, 2016, PG&E issued a license for grazing and agricultural purposes to Robert Blanchard, Jr. This license expires June 5, 2021, but may be renewed.

On March 4, 2013, PG&E issued a license to use a house located on the North Ranch to Jim Blecha and Sally Krenn on a month-to-month basis to serve as an on-site presence to oversee the use of the Point Buchon trail.

On September 1, 2013, PG&E issued a license to GTE Mobilenet of Santa Barbara Limited Partnership for telecommunication facilities on Parcel P. This license expires in 2022, but may be renewed until 2027.

C. Description of the Acquisition and Ownership History of the Lands

1. Lease of Parcels P, T, L and R

PG&E is currently the lessee under that certain Lease dated September 17, 1966, originally entered into between Luigi Marré Land & Cattle Co. (LMLCC), as lessor, and San Luis Obispo Bay Properties, Inc. (SLOBP), as lessee, pertaining to lands comprising the Diablo Canyon plant site (Parcel P), transmission line corridor (Parcel T), an easement for use as an access road between Parcel P and Avila Beach Drive (Parcel R), and a large coastal shelf extending southerly of the plant site (Parcel L) (the “Properties lease”). The term of the Properties lease is 99 years.

By way of background, PG&E had previously been the sublessee of the Properties lease. This sublease was dated September 17, 1966, SLOBP, as sublessor, subleased to PG&E, as sublessee, Parcel P, Parcel T and Parcel R. In the 1970s, SLOBP filed for bankruptcy. As a result of the bankruptcy proceedings, PG&E acquired SLOBP’s leasehold interest in the Properties lease. This acquisition is memorialized in the Assignment of Lease dated July 28, 1980, by John F. Ready, as trustee in the bankruptcy of SLOPB, and recorded on July 29, 1989 as Instrument No. 32982 in Volume 2258, Page 67 of Official Records of San Luis Obispo County. As a result of this Assignment of Lease, PG&E became the successor in interest to the lessee under the Properties lease. At all times since this Assignment of Lease, PG&E has remained the lessee under the Properties lease. The Properties lease is included in PG&E’s rate base.

2. Lease of Lots W and Z and the Diablo Northwest Parcel

PG&E is currently the lessee under that certain Lease dated December 26, 1968, originally entered into between LMLCC, as lessor, and Diablo Canyon Corporation (DCC- no relationship to PG&E), as lessee, pertaining to lands comprising Lots T, U, V, W, X, Y and Z of the Hartford Subdivision of the Rancho San Miguelito and a parcel known as the Diablo Northwest Parcel in the Rancho Pecho (the "Diablo lease"). The term of the Properties lease is 99 years.

As part of the bankruptcy proceedings of DCC, PG&E acquired DCC's leasehold interest in the Diablo Northwest Parcel. This acquisition is memorialized in the Assignment of Lease dated July 28, 1980, by John F. Ready, as trustee in the bankruptcy of DCC, and recorded on July 29, 1989, as Instrument No. 32983 in Volume 2258, Page 80 of Official Records of San Luis Obispo County.

On December 19, 1985, PG&E acquired the leasehold interest in Lots W and Z. This acquisition is memorialized in the Assignment of Lease by Graylor Investment, Inc., and recorded on January 31, 1986, as Instrument No. 5960 in Volume 2796, Page 773 of Official Records of San Luis Obispo County.

The Diablo Northwest Parcel, Lots W and Z are included in PG&E's rate base.

3. Eureka Energy Company's Acquisition of Fee Title to the South Ranch (Parcels P, T, L and R, the Diablo Northwest Parcel and Lots T, U, V, W, X, Y, and Z)

By Sheriff's Deed dated April 5, 1995, Eureka acquired the fee interest to Parcels P, T, L and R, the Diablo Northwest Parcel and Lots T, V, U, X, W, X, Y and Z, subject to certain existing exceptions described in the Sheriff's Deed. Title to these properties were acquired by Eureka Energy Company so that PG&E's existing leasehold interest in the Properties lease and Diablo lease would continue in full force and effect. As a result of acquiring the fee title, Eureka Energy Company is successor in interest to LMLCC, as lessor, under the Properties Lease. As noted above in Section A.3, PG&E is the successor in interest to the lessee under the Properties Lease. Eureka is also the successor in interest to LMLCC, as lessor, under the Diablo Lease. As noted above in Section B.2 and B.3, PG&E is the successor in interest to the lessee under Diablo lease as to the Diablo Northwest Parcel and Lots W and Z. Eureka also is the owner of certain lands that are not subject to either the Properties lease or the Diablo lease, including a 5.21-acre parcel of land on Lot Z (APN 076-172-016) and a 2 acre area of land on Lot Y (076-172-022) commonly known as the Marre House.

Eureka's fee title to Lots T, U, V, X, and Y (comprising approximately 2,369 acres) is subject to the Diablo lease. Currently, Pacho Limited Partnership, a California limited partnership, and San Luis Bay Limited Partnership, a California limited partnership, hold the leasehold interest in the Diablo lease to Lots T, U, V, X, and Y. According to SEC filings, HomeFed Corporation, a Delaware corporation with its principal office in Carlsbad, California holds a 90 percent controlling interest in Pacho Limited 4. These properties are commonly referred to as Wild Cherry Canyon.

4. PG&E's Acquisition of Fee Title to North Ranch

In 1968, PG&E acquired title to 168 acres of land lying north of and contiguous to Parcel P. This acquisition is memorialized in the grant deed dated March 4, 1968, and recorded on March 8, 1968, in Volume 1468, Page 49 of Official Records of San Luis Obispo County.

In 1986, PG&E acquired title to an additional 4,517 acres of land on the North Ranch, lying between Parcel P and Montana del Oro State Park. These acquisitions were memorialized in 4 separate grant deeds from the Fields family: (1) Grant Deed dated November 25, 1986, and recorded on December 18, 1986, as Instrument No. 84013 in Volume 2927, Page 154 (conveying 3,104 acres); (2) Grant Deed dated November 25, 1986, and recorded on December 18, 1986, as Instrument No. 84014 in Volume 2927, Page 158 (conveying 457 acres); (3) Grant Deed dated December 12, 1986 and recorded on December 18, 1986, as Instrument No. 84015 in Volume 2927, Page 159 (conveying 899 acres); and (4) Grant Deed dated November 25, 1986, and recorded on December 18, 1986, as Instrument No. 84014 in Volume 2927, Page 161 (conveying 57 acres). These properties in the North Ranch are included within PG&E's rate base.

5. PG&E's Lease From the California State Lands Commission

In 2016, PG&E received a new lease from the California State Lands Commission (CSLC) for use of tidelands and offshore areas for use of a cooling water discharge channel, water intake structure, intake cove breakwaters and related structures associated with the operation of the power plant through 2025.

D. Diablo Canyon Decommissioning Engagement Panel and Other Public Outreach

In D.18-01-022, the Commission directed:

> Pacific Gas and Electric Company will take no action with respect to any of the lands and facilities, whether owned by the Utility or a subsidiary, before completion of a future process; there will be local input and further Commission review prior to the disposition of Diablo Canyon facilities and surrounding lands.[1]

In response to this directive, PG&E established the Diablo Canyon Decommissioning Engagement Panel (DCDEP or Engagement Panel) to engage in open and transparent dialogue with all interested stakeholders on matters regarding decommissioning and future use of the lands around DCPP. The Engagement Panel was established and adopted its charter as of May 24, 2018. As of December 1, 2018, the panel has held seven public meetings which were noticed in advance to solicit public attendance and participation. In addition to these meetings, the DCDEP held 28 hours of workshops over four days where participants brainstormed and shared ideas about repurposing DCPP facilities and structures and potential future uses of DCPP lands.

In addition to these DCDEP meetings and workshops, PG&E engaged and received feedback from regulators, key stakeholders, appointed and elected officials, and DCPP employees regarding DCPP operations, the potential repurposing of DCPP assets, and the proposals for potential future use (or conservation) of DCPP lands.

From these engagements and DCDEP meetings, PG&E learned that the public is most interested in repurposing the breakwaters at DCPP and in repurposing the property owned by Eureka known as Wild Cherry Canyon, a portion of the South Ranch property, for future use or conservation.

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[1] D.18-01-022, Ordering Paragraph (OP) 13.

PG&E proposes to continue these engagements with the public and when plans for future use of DCPP lands and facilities move beyond a brainstorming and evaluation phase, PG&E will bring these proposals to the Commission as required.

1. Breakwaters

The breakwaters extend from two points into the ocean, creating an area of calm surface water around the intake structure. As explained in more detail in Chapter 4, Section E.1., they are built from man-made concrete tri-bar (concrete block in a complex geometric shape weighing up to 38 tons) and used to protect harbor walls from the erosive force of ocean waves

PG&E received public input regarding the breakwaters through the DCDEP, public workshops on proposed repurposing/reuse options, public comments during DCDEP meetings, emails directed to DCDEP members, consultation with potential future operators, such as the Port San Luis Harbor District, and the CSLC staff. These entities and stakeholders have expressed significant interest in repurposing the breakwaters. Suggestions for repurposing or reuse include: marina, commercial fishing, recreational diving, sailing, motor boat access, Marine Research (generic, scientific), Cal State University System marine research, Cal State University System—marine maritime academy, harbor of safe refuge, and marine mammal and wildlife rescue facility

PG&E has identified several steps necessary to implement any of these repurposing proposals. In one scenario, PG&E would have to transfer the breakwaters to another entity and CSLC would have to transfer the current lease or issue a new lease.

In a different scenario, the legislature could pass legislation to transfer ownership to another governmental entity.

PG&E is also considering maintaining the breakwater for future public access and utility operations.

In addition to the ownership issues, PG&E must evaluate regulatory and permitting requirements for any repurposing/reuse proposals for DCPP lands. Agencies with jurisdiction may include, but are not limited to: CSLC, CCC, US Army Corps of Engineers, National Marine Fisheries Service, US

Fish and Wildlife, California Division of Fish and Wildlife, California EPA, Water Resources Control Board, and San Luis Obispo County.

Furthermore, the CSLC Executive Director's written correspondence to PG&E dated November 21, 2018, reiterated that staff cannot speculate as to what action the CSLC Commissioners may ultimately take on the breakwater. The CLSC will evaluate consistency with the Public Trust Doctrine and California Environmental Quality Act (CEQA) to determine if any proposal is in the best interest of California.

Evaluating scenarios and pursing the permitting necessary for repurposing/reuse proposals may take considerable time and money—indeed, the proposed repurposing may have one-time and/or ongoing costs, but repurposing/reuse may be less impactful to the environment and may cost less than the approximately $286 million cost to remove and dispose of the breakwaters.

2. Wild Cherry Canyon

The Engagement Panel and other public outreach revealed multiple parties interested in ensuring that a portion of the South Ranch property known as Wild Cherry Canyon be dedicated to conservation. In conjunction with this expressed preference, stakeholders have suggested that there may be an opportunity for acquisition because the voters of California recently passed a park bond to provide funding for open space acquisitions. The Friends of Wild Cherry Canyon, the State of California, the County of San Luis Obispo and other NGOs are assessing how to acquire the Wild Cherry Canyon parcels from Eureka Energy Company and Homefed Corporation for conservation. These properties were part of a complex, open-space acquisition effort that involved many of the same stakeholders that ultimately failed in 2013.

E. Agency Consultations

The 2015 NDCTP decision directed PG&E to provide "a summary and results of consultation with the California Coastal Commission (CCC), CSLC, Department of Public Health (DPH), California State Water Resources Control Board (SWQCB), and the Department of Toxic Substances Control (DTSC) concerning the application of EO D-62-02 to disposal of construction debris and whether the breakwaters will be required to be removed at Diablo Canyon Power Plant."[2]

In compliance with the Commission's directive, PG&E engaged in initial, informal communication with each all of the referenced agencies and then scheduled in-person meetings to discuss each agency's role with both the EO and the potential retention or removal of the breakwater features.

These consultations did not provide additional clarity on the issue of in-state disposal opportunities for construction debris from DCPP. The CCC, CSLC, and DTSC conveyed that they do not have jurisdiction in the matter, unless the issue of in-state versus out-of-state disposal is included as part of the project description for which an application is made requiring discretionary action.

The SWQCB informed PG&E that they are aware of the EO and have taken no further action since a 2008 memorandum to the Bureau of State Audits in which states in relevant part:

> While the EO did include adoption of waste discharge requirements, this has not yet occurred because there would be no additional regulatory benefit gained and other high-priority work continues to compete for limited resources. Therefore, issuance of waste discharge requirements has been deferred until such time as there is a clear and compelling benefit to direct resources for such action.

Finally, the DPH informed PG&E that they do not regulate nuclear power plants and only review documents provided by the Nuclear Regulatory Commission (NRC) as a "sister agency" to ensure nothing seems to be abnormal in its reporting on decommissioning activities within California. The DPH reiterated they do not regulate either DCPP or the landfills, and they recognize the SWQCB has not issued further formal guidance to landfill operators since the adoption of the moratorium.

In addition to these agency consultations, PG&E contacted landfills in California to inquire whether the landfills would accept NRC released construction debris. A few of the landfills contacted indicated they would accept this waste, but only if provided guidance or authority from the State to do so.

In summary, the state agencies have taken no further action to address the EO and the landfills contacted by PG&E are not willing to accept DCPP waste without formal state guidance addressing the EO. PG&E concludes that there is

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[2] D.17-05-020, OP 7.

insufficient guidance from the State for PG&E and landfill operators to rely on to dispose of DCPP construction debris that is above background radiation levels but below DCGLs established by the NRC in state landfills. Accordingly, PG&E's Decommissioning Cost Estimate (DCE) assumes out of state disposal of this waste.

With regard to disposition of the breakwaters, the state agencies provided more clarity. The agencies involved in discretionary permitting or action—the CSLC and the CCC—indicated they would require a specific application and project description to evaluate an outcome and comply with California environmental regulations regarding the breakwaters. The agencies concur that the CSLC has exclusive authority to determine whether the breakwater may be retained, modified, or removed under terms of the current lease, which must be renewed prior to plant shut down. As such, further action is required by the CLSC and PG&E before the CSLC can take action regarding retention or removal of the breakwaters. Proposals to remove or retain the breakwaters trigger environmental review under CEQA (or CEQA equivalent) to evaluate potential impacts and alternatives of the proposed project. The CSLC Executive Director confirmed the CSLC cannot speculate on retention of breakwaters or new lease terms until PG&E applies for its decommissioning activities (which is part of the current lease from CSLC to PG&E).

The CCC may have secondary permitting authority associated with disposition of the breakwaters because it may take the position that proposals to remove or retain the breakwaters constitute development under the Coastal Act.

F. Environmental Permits

The 2015 NDCTP decision directed PG&E to include in its 2018 application testimony a report on the environmental reviews required to decommission DCPP.[3] PG&E's decommissioning plan involves numerous agency reviews and required permits and close coordination with federal, state, and local agencies. The DCE Section 3.2.1 sets forth in detail the relevant requirements and PG&E's plans for obtaining the expected necessary permits and approvals.

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[3] D.17-05-020, p 66.


PACIFIC OCEAN
PARCEL P
PARCEL T
NORTHWEST DIABLO PARCEL (NWD)
PARCEL R
PARCEL L
LOT T
LOT U
LOT V
LOT W
LOT X
LOT Y
LOT Z
DCPP
POINT BUCHON TRAIL
DCPP NORTH ROAD ACCESS
DCPP ACCESS ROAD
PECHO COAST TRAIL
LIGHTHOUSE ROAD
OVERLOOK TRAIL
Map Legend
Access Road
Access Road North
Pecho Coast Trail
Buchon Trail
Coastal Zone
PG&E Fee Parcels
Eureka Energy Company Fee Parcels
Leased to PG&E
Leased to HomeFed
Site Boundary
Pending Conservation Space (1,200 acres)
Reference Table
1 GTE Mobilnet (Verizon) Site License Agreement for telecommunication equipment
2 California State Lands Commission Lease to PG&E for Water Discharge Channel and Intake Structure
3 Properties Lease to PG&E: Plant (Parcel P), Transmission Lines (Parcel T), (Parcel L) and Road (Parcel R)
4 Grazing and Agricultural License to Mello
5 License to Mello for Marre House
6 Road Easement to Martin
7 Grazing License for Blanchard
8 1,200-Acre Deed Restriction Area
9 Point Buchon Deed Restriction Area
10 License to Blecha for North Ranch House

DCPP Lands

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

SPENT NUCLEAR FUEL

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
SPENT NUCLEAR FUEL

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
SPENT NUCLEAR FUEL

A. Introduction

The purpose of this chapter is to (1) present Pacific Gas and Electric Company's (PG&E or the Utility) analysis of the feasibility of both pre-and post-shut down acceleration of dry cask loading at Diablo Canyon Power Plant (DCPP) and identify the costs to expedite dry cask loading; (2) provide an updated assessment of the commencement of Department of Energy (DOE) spent nuclear fuel (SNF) pickup; and (3) describe the status of PG&E's DOE settlement and the return of DOE net settlement payments to customers.

B. Acceleration of Dry Cask Loading at DCPP

In the 2015 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) decision, the California Public Utilities Commission (Commission) directed PG&E to include in PG&E's 2018 NDCTP an assessment of both pre-shutdown and post-shutdown options for expediting dry cask loading from the 10-year assumption authorized in the 2015 NDCTP, and the associated costs.[1]

PG&E's assessment of the feasibility, duration and cost of accelerating SNF loading to dry cask storage pre-and post-shutdown reveals that the most cost-effective strategy is to eliminate SNF loading campaigns between now and permanent cessation of operations and to implement one loading campaign starting in 2030 and ending within seven years after Unit 2 shutdown. This loading strategy results in completing transfer of the SNF in dry cask storage 1.4 years earlier than the next most feasible proposal, taking into account required cooling time, the heat load limits of canisters, licensing, seismic and other constraints.

The controlling factor in loading casks is the heat load of each SNF assembly. For every relatively hot fuel assembly loaded in the canister an equally cool fuel assembly, relative to the average heat per SNF assembly, needs to be loaded. The relative temperature of a SNF assembly is primarily based on how long it has been cooling in the spent fuel pool (SFP)—the longer it

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1 Decision (D.) 17-05-020, Ordering Paragraph (OP) 5.

is in the SFP the cooler it is. Any strategy for accelerating transfer must take into consideration the entire mix of SNF assembly heat loads contained within the SFPs currently and through the remainder of the operating licenses.

1. Status of Dry Cask Loading at DCPP

The DCPP reactor pressure vessels are designed to hold a core of 193 fuel assemblies. The cores are designed to run at full power for approximately 20 months before the fuel is taken out of the reactor pressure vessel and placed in the SFP to allow for a refueling outage when a new core is loaded into the reactor pressure vessel. The time that the reactor is operating between refueling outages is referred to as a cycle. The new core loaded during a refueling outage typically contains approximately a third each of new fuel assemblies that have never been in the core, fuel assemblies that have been in the core for one cycle, and fuel assemblies that have been in the core for two cycles.

Typically, once a fuel assembly has been in the core for three cycles it will no longer be used in a future core and will remain in the SFP to cool until it has met the heat load parameters for it to be transferred to dry cask storage. Once the SNF is placed in a dry storage canister it is transferred to the Independent Spent Fuel Storage Installation (ISFSI) where it will be maintained until it can be transferred to an offsite licensed facility.

As of December 2018 there are a total 1,856 SNF assemblies stored within the ISFSI. The SNF assemblies are stored within 58 Holtec HI-STORM 100 casks, with 32 assemblies per cask. There are currently 744 and 768 SNF assemblies stored in the Unit 1 and 2 SFPs, respectively. PG&E anticipates that when DCPP Unit 2 is shut down for the last time, there will be 1,261 and 1,281 SNF assemblies stored in the Unit 1 and 2 SFPs, respectively.

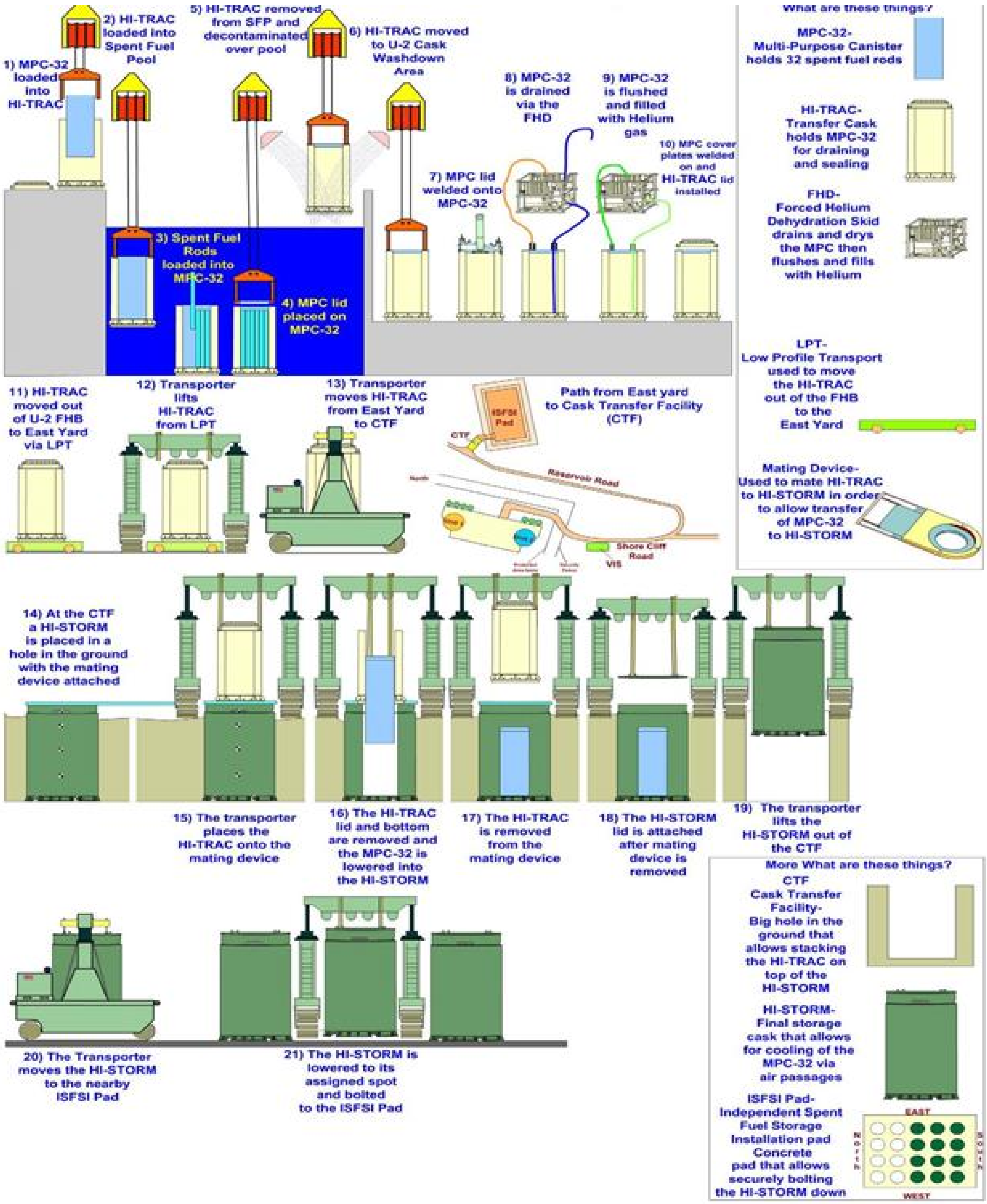
2. NRC Licensing Requirements for Dry Cask Loading at DCPP

The current dry cask storage system at DCPP uses the Holtec International HI-STORM 100SA overpack, HI-TRAC 125D transfer cask, and Multi-Purpose Canister (MPC) capable of holding 32 fuel assemblies (MPC-32). This system is approved for use by general licensees under Nuclear Regulatory Commission (NRC) Docket Number 72-1014.

For a general license, the dry cask vendor performs the licensing to gain the NRC's approval for the dry cask design to be used. However, DCPP is not authorized as a general licensee, but rather uses the system under a site-specific ISFSI license (NRC Docket Number 72-26). PG&E chose to obtain a site-specific ISFSI license to adequately address DCPP site-specific conditions including seismic design basis requirements and the associated impacts to the system's thermal capacity.

The DCPP site-specific seismic conditions require that potential impacts be evaluated in detail for seismic response of the storage system during an earthquake and for the potential of thermally limiting configurations (i.e., when there is the least amount of margin as compared to the allowable design heat load) during the process of transferring SNF from the SFP to the ISFSI. To meet DCPP site-specific seismic design requirements, PG&E implemented a one-of-a-kind anchored cask design for the current Holtec vertically orientated storage system. The current storage system's most thermally limiting configuration is while the loaded storage cask is in the cask transfer facility (CTF) (see Figure 6-1, steps 17 and 18) because the CTF limits the air flow around the canister. PG&E implemented DCPP's design of a below grade CTF in order to minimize the seismic spectral response of the overpack and transfer cask while the transfer cask is connected to the storage cask to allow the loaded canister to be transferred from transfer cask to the overpack (see Figure 6-1, steps 15 and 16). For other plants with the HI-STORM system the overpack is placed on the ground and the transfer cask is placed on top of the overpack. The loading configuration used at other plants would not meet NRC requirements when using DCPP's seismic spectrum.

FIGURE 6-1
OVERVIEW OF DCPP CASK LOADING PROCESS



The minimum time allowed under NRC requirements before SNF can be removed from the SFP and placed into dry storage is dependent on three factors. The first factor is burnup, which limits the maximum total heat load the NRC approves for a canister design. The second factor is the maximum total heat load the NRC has approved for a canister design. The third factor is the maximum heat load for a single SNF assembly the NRC has approved for a canister design. The maximum heat load for a single SNF assembly is imposed to ensure the localized physical properties of the canister design are not impacted for storage and transportation requirements (e.g., ensures the material is not weakened from high localized temperatures); it determines the shortest cooling time that the NRC will allow before any assembly may be placed in dry cask storage.

To conceptualize burnup, it helps to understand how uranium fuels a reactor. Before it is made into fuel, uranium is processed to increase the concentration of atoms that can split in a controlled chain reaction in the reactor. The atoms release energy as they split; this energy produces the heat that is turned into electricity. In general, the higher the concentration of those atoms, the longer the fuel can sustain a chain reaction. And the longer the fuel remains in the reactor, the higher the burnup. In other words, burnup is a way to measure how much uranium is burned in the reactor. It is the amount of energy produced by the uranium, expressed in gigawatt-days per metric ton of uranium (GWd/MTU).

Over time, nuclear fuel designs have improved to allow for a higher average burnup. Utilities now can get more power out of their fuel before replacing it, which means they can operate longer between refueling outages while using less fuel. The burnup level affects the fuel’s temperature, radioactivity, and physical makeup. It is important to the NRC’s review of SNF cask designs because each system has limits on temperature and radioactivity. How hot and radioactive SNF is depends on burnup, the fuel’s initial makeup and conditions in the core. All these factors must be considered in designing and approving dry storage and transport systems for SNF.

The NRC’s standard approach for approving maximum heat loads for a dry cask design is based on whether the canister will contain SNF assemblies with a burnup greater than 45 GWd/MTU. The canisters that will contain one or more SNF assemblies with a burnup greater than 45 GWd/MTU will have a maximum heat load limit that is lower than that of a canister that will contain only SNF assemblies with equal to or less than 45 GWd/MTU.

Once the maximum heat load limit for a canister is determined, if it will contain a SNF assembly with greater than 45 GWd/MTU, the utility must determine which SNF assemblies from the inventory of SNF in the SFPs it can load into the canister while remaining below the maximum heat load total for the canister while still meeting the maximum heat load limit for a single fuel assembly.

There are only so many total kilowatts of heat allowed to be initially stored in a canister. Dividing the total number of kilowatts allowed for a canister by the number of SNF assemblies that can be stored in the canister provides the average heat load allowed per SNF assembly to be stored in the canister. For every SNF assembly to be stored in the canister that has a heat load above the average heat load allowed per SNF assembly for the canister, PG&E must load a SNF assembly that has a heat load an equivalent amount below the average load allowed per SNF assembly for the canister. Essentially, for every relatively hot fuel assembly loaded in the canister an equally cool fuel assembly, relative to the average heat per SNF assembly, needs to be loaded in the canister. The relative temperature of a SNF assembly is primarily based on how long it has been cooling in the SFP. Any strategy for emptying the SFP of SNF must consider take the entire mix of SNF assembly heat loads contained within the SFPs currently and through the remainder of the operating licenses.

In addition to the maximum heat load limits, there are additional design basis criteria, such as natural disasters, that must be approved by the NRC for a dry cask storage design. The design basis criteria are based on site-specific conditions. The dry cask storage system general licenses do not bound every site-specific condition and require additional licensing, potential design changes, and NRC approval to allow the use of a generally licensed design at a site that has a condition not bounded by the general license.

3. Alternatives for Acceleration of Dry Cask Loading

The current dry cask storage design in use at Diablo Canyon ISFSI (DC ISFSI) is limited by the ISFSI Technical Specifications to a minimum cooling of 10 years for the amount of burnup of the DCPP SNF. The Technical Specifications limits are based on the design basis accident evaluations using the physical properties of the storage system. The thermally limiting component for the current DC ISFSI system is the SNF fuel basket. To accelerate transition from wet storage to dry storage of SNF before a 10-year cooling time, a dry cask storage design system with a heat load capacity higher than the one currently licensed by the NRC for the DC ISFSI will need to be implemented.

There are three major vendors with dry cask storage system designs approved by the NRC for use in the United States. Those three vendors are Holtec International (Holtec), NAC International (NAC), and Orano (formerly known as and referred to here as TransNuclear (TN) Americas). The Holtec and NAC dry storage systems implement storage configuration with the SNF in a vertical orientation. The TN Americas dry cask storage system implements a storage configuration with the SNF in a horizontal orientation. All three of these vendors have gained approval, or are pursuing approval, from the NRC for canister designs with similar maximum heat loads.

To implement a new design for the DC ISFSI from any of the three above mentioned vendors would require PG&E to pursue one of two options. Option 1 would be to get NRC approval to amend the site-specific DC ISFSI license to incorporate a generally licensed design. Option 2 would be to perform an evaluation to demonstrate that the general licensed design bounds the site-specific conditions at DCPP.

If the evaluation determined that the general design did not bound the site-specific conditions, then NRC approval to amend the general license with design changes to bound the DCPP site-specific conditions would have to be obtained prior to the system could be implemented. Once a vendor is selected and under contract to perform the required analyses and evaluations to determine the design and licensing bases changes needed to implement a new system, a duration of three years would be a reasonable expectation to complete the analyses and receive NRC approvals.

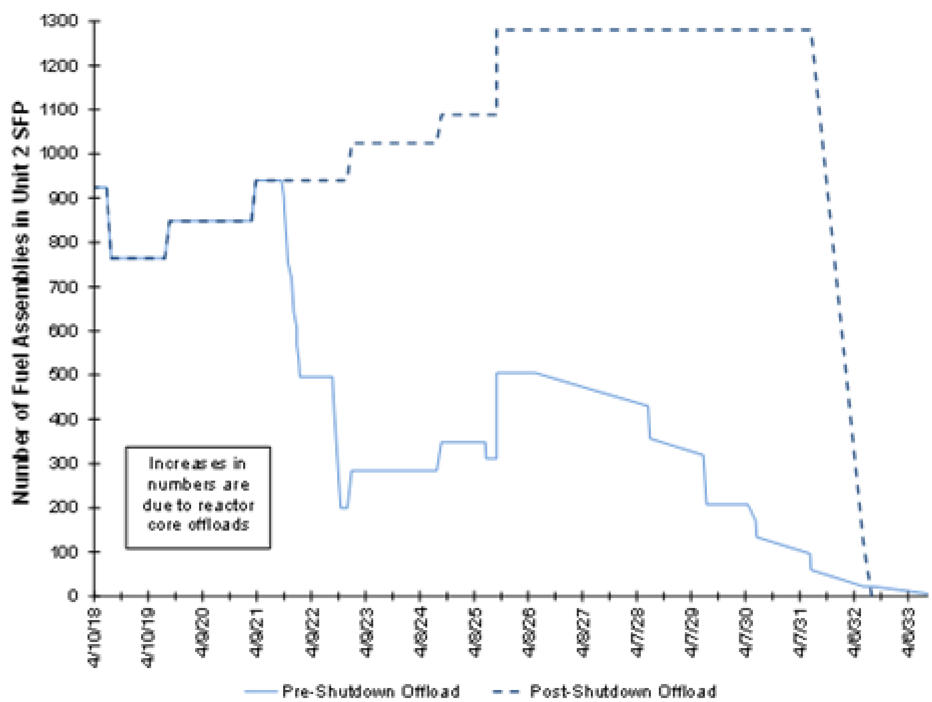
The duration for receiving NRC approval is dependent on the significance of any design change that would be needed and if any public hearings are required by the process. An amendment to a general ISFSI license may also be complicated by any other license amendments that would be concurrently under review by the NRC for other users of the general design.

In 2017, PG&E evaluated options for expedited transfer of SNF and assessed the cost-effectiveness and regulatory and operational risks and benefits associated with these options. The Holtec and NAC designs are very similar with the only notable difference being that the NAC design is larger dimensionally and heavier than those of Holtec. Based on these similarities PG&E only evaluated Holtec and TN Americas in greater detail. With similar storage capabilities between Holtec and NAC PG&E assumed that any design changes needed to implement a NAC system versus a Holtec system would be similar or greater in difficulty and cost. For both Holtec and TN Americas, multiple systems/designs were evaluated along with multiple loading scenarios to optimize the date that the last SNF would be removed from the SFPs.

PG&E has concluded that pre-shutdown acceleration of the SNF offload schedule would result in SNF being in the SFPs longer than if SNF is maintained in the SFPs until a single offloading campaign after DCPP is shutdown. This is driven by the fact that during decommissioning the hottest fuel assemblies in the SFP will be those that were in the reactor core at the time of the final shutdown. The relatively high heat loads and the burnup of these SNF assemblies will be the limiting factor on how soon all the SNF assemblies may be placed into dry cask storage.

As explained above, SNF assemblies with lower relative heat loads will be needed to offset the higher heat loads of the SNF assemblies that will be in reactor core at the final shutdown to meet the maximum heat load limit for the canister. If pre-shutdown dry cask storage were to be accelerated it would offload SNF assemblies to dry cask storage sooner, and therefore, not allow them to cool longer in the SNF pools and lower their relative heat loads. Therefore, to accelerate all SNF assemblies being in dry cask storage, the current inventory of SNF assemblies should remain in the SFPs to allow them to cool longer and lower their relative heat load to offset the relatively higher heat loads of the SNF assemblies that will be in the reactor core at the final shutdown. Figure 6-2 provides a graphic example of the above description on the impact of pre-shutdown offloading versus post-shutdown offloading, with the assumption that a dry cask storage system with a higher heat load capacity is licensed and available for implementation at the DC ISFSI in 2021, for illustrative purposes only. As shown in this figure, by offloading SNF pre-shutdown, the final SFP offload date is increased by 1.4 years as opposed to only offloading SNF post-shutdown.

FIGURE 6-2
SPENT FUEL POOL OFFLOAD EXAMPLE
COMPARING PRE-SHUTDOWN VERSUS POST-OFFLOAD



Accelerating pre-shutdown transfer from wet to dry storage will result in SNF being in the SFPs longer, and therefore, would result in higher costs and a longer total duration for decommissioning. The annual cost for security, SFP cooling operations, NRC fees, and insurance is $54.7 million higher for every additional year the SNF is in wet storage versus dry storage. The total increase in costs associated with accelerating pre-shutdown transfer of SNF from wet to dry storage would be in excess of $54.7 million as there would also be the additional costs for the mobilization and demobilization of the dry cask storage vendor and associated equipment for any offload campaigns that would be performed, and the costs associated with the project oversight for the resulting additional decommissioning project duration.

4. Comparison to Similar Facilities

Dry cask storage systems are designed and licensed for boiling water reactor or pressurized water reactor (PWR) fuel and may only contain SNF from the corresponding reactor design. DCPP uses a PWR design.

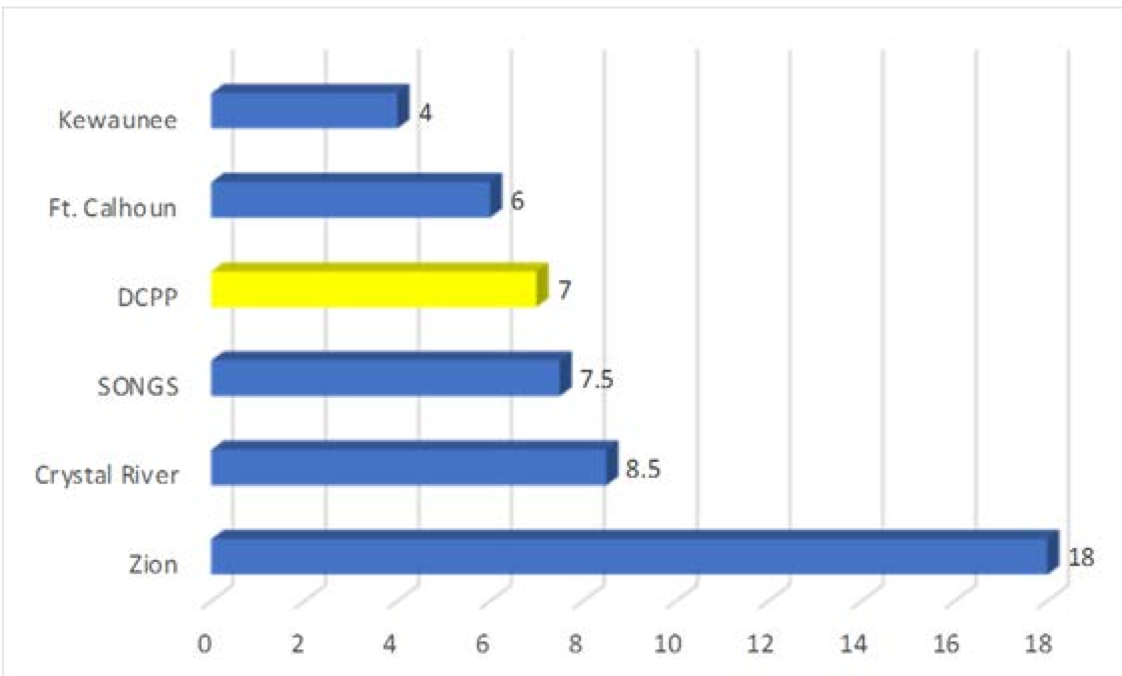
There are eight PWR power plants that have entered, but not completed decommissioning or have announced a retirement date. Of the eight PWR power plants, five have completed or officially communicated their proposed schedule to complete the transfer of SNF to dry cask storage through a Post Shutdown Activities Report (PSDAR) to the NRC. The average SNF transfer duration of these five PWR power plants is approximately 8.5 years. Figure 6-3 identifies the number of years these five PWR power plants estimate they will need to complete the transfer of SNF to dry cask storage.

Only Kewaunee implemented, and Fort Calhoun has officially stated in its PSDAR that it intends to complete, transfer of all SNF to dry cask storage in less than seven years. Kewaunee implemented a NAC general license design to complete the transfer of all SNF to dry cask storage within approximately four years. Fort Calhoun has forecast completing the transfer of all SNF to dry cask storage in approximately six years. Fort Calhoun is planning to use a general licensed TN America dry cask storage system.

At the time that Kewaunee and Fort Calhoun shutdown, these two plants had approximately one-tenth of the amount of high burnup fuel that DCPP is forecast to have at final shutdown for Units 1 and 2. As a result, these two plants had a final SNF inventory requiring fewer casks with more limiting heat loads, and therefore significantly greater flexibility in cask loading options than is expected for DCPP.

Additionally, the site-specific seismic design basis for Kewaunee and Fort Calhoun are lower than the design basis requirements for DCPP. As stated earlier, the impacts of the DCPP site-specific seismic conditions must be evaluated in detail for seismic response of the storage system during an earthquake and the potential of thermally limiting configurations, such as a storage cask loaded with SNF while in the CTF, during the process of transferring SNF from the SFP to the ISFSI. The general licensed NAC and TN Americas dry cask storage system designs do not meet the current DC ISFSI design and licensing bases and would require additional NRC review and approval for any design changes that would be needed to meet the DC ISFSI site-specific seismic design basis requirements, which may result in a lower maximum heat load limit from the NRC.

FIGURE 6-3
DURATIONS IN YEARS TO COMPLETE THE TRANSFER OF SNF TO DRY CASK STORAGE



5. Transition From Wet to Dry Spent Nuclear Fuel Storage in Seven Years

PG&E has determined that expediting post-shutdown transfer of SNF to dry cask storage from the 10-year ISFSI Technical Specification limit used in the 2015 NDCTP decommissioning cost estimate (DCE), to seven years of shutdown is technically feasible with the implementation of a new storage system with a higher heat load capacity. The assumption of a seven-year offload duration post-shutdown is similar to the timeframe San Onofre Nuclear Generating Station will complete its transfer of SNF to dry cask storage, which is currently forecast to be completed 7.5 years after its shutdown date.

PG&E looked at dry storage system designs that are currently under review by the NRC with a high likelihood of being approved by the NRC which would be bounding of DCPP site-specific conditions prior to the Unit 2 shutdown date. To implement a new storage system will require a request for proposal from vendors. PG&E intends to provide DCPP specific information to selected vendors to enable them to identify design and licensing bases changes that will be required for a new storage system to meet the DCPP site-specific requirements. The proposals from the vendors will include the costs for design and licensing bases changes, implementation of changes and new system components, and purchase of new system components.

PG&E expects to evaluate the proposals and select one. Once the selected vendor is under contract then the design and licensing change process will start and conclude with the required approvals from the NRC. Once NRC approval is obtained then physical modifications at the plant can commence for implementation of the new storage system.

Technology for dry cask storage is continuously improving and the potential for shorter SNF cooling times may be expected. But, as these designs have not been approved by the NRC for the DC ISFSI at this time, and there remains a significant uncertainty as to the maximum heat load limits the NRC may require for the DCPP site-specific seismic design basis, it is reasonable to assume that SNF assemblies will be transferred to the ISFSI within seven years of Unit 2 shutdown.

C. Annual Costs of Wet Versus Dry Spent Nuclear Fuel Storage

Determining the annual costs of wet SNF storage versus dry SNF storage is a complex process that includes consideration of multiple variables. An example of a variable that has significant cost impacts is the location of reactor segmentation waste, which includes greater-than-Class-C (GTCC) waste, in comparison to the SNF and its impact on required security personnel. A brief explanation of this one example is provided below to demonstrate the complexity of the annual cost difference. The annual cost difference for this one example is also provided.

To simplify the calculation of annual cost savings of wet versus dry SNF storage, PG&E assumed that the reactor components have had adequate time to allow enough radioactive decay to occur to allow the reactor segmentation and transfer of GTCC waste to DC ISFSI to be completed in seven years. This results in no remaining radiological security needs at the plant site and would reflect an ideal scenario of the most cost savings from the transition. The annual security cost savings from the transition from wet to dry SNF storage under this assumption is $34.6 million.

The above cost savings does not account for several other variables which also have complex interactions with the transition from wet to dry SNF storage, such as insurance, NRC license fees, and the costs to operate the SPF cooling system. A rough estimate for annual cost savings from the transition from wet to dry storage costs for these items is $20.1 million.

D. Estimated Commencement of DOE SNF Pickup

Congress passed the "Nuclear Waste Policy Act" in 1982, assigning the federal government's long-standing responsibility for disposal of the SNF created by the commercial nuclear generating plants to the DOE and required the DOE to establish repositories for the disposal of this radioactive waste. PG&E, along with other nuclear power plant operators, entered into a standard nuclear SNF disposal agreement with the DOE; these agreements provide that starting January 31, 1998, DOE would pick up SNF to transport it to a permanent repository.

DOE has never established a permanent repository or interim facility, and DOE has never picked up any SNF. In its decommissioning estimates PG&E assumes that it will continue to incur these costs until the date it assumes DOE will have completed picking up SNF.

In the 2015 NDCTP, the Commission directed PG&E to provide any new information as to an estimated time frame for DOE to begin pick-up of SNF at DCPP and Humboldt Bay Power Plant (HBPP), or change in circumstance as to any progress with approvals for a permanent or long-term off-site repository for SNF.[2] Sections 3.5.7 and 3.5.8 of the DCPP Site Specific DCE discuss in detail developments since the filing of PG&E's 2015 NDCTP application.

In summary, there is no new substantive information from DOE or any other source since the last NDCTP decision was issued with respect to the timing of

2 D.17-05-020, OP 10 and p. 66.

the actual date upon which DOE will commence picking up SNF. Many complex technical, political, and administrative decisions remain which will eventually drive the development by DOE of any interim or long-term storage of SNF. Consistent with Commission decisions in previous NDCTPs, PG&E therefore believes it is reasonable to assume a 3-year delay in commencement of the start date for DOE initiating transfer of commercial SNF from 2028, as adopted in the 2015 NDCTP, to 2031.

In light of the DOE's original generator allocation/receipt schedules based upon the oldest fuel receiving the highest priority; information available on the projected rate of transfer; and the backlogged national queue, PG&E assumes that DOE would commence picking up SNF at HBPP in 2031, and at DCPP in 2038. Different DOE acceptance schedules may result in different completion dates.

E. Status of DOE Litigation

In the 2015 NDCTP, the Commission directed PG&E to provide the status of the settlement between PG&E and DOE concerning reimbursement for SNF management costs and how PG&E is crediting settlement funds back to customers.[3] As discussed above, the government was to begin accepting spent fuel on January 31, 1998 but the DOE failed to meet this date and has yet to receive any spent fuel. The DOE and the affected utilities have been engaged in litigation ever since the DOE failed to meet its obligations.

PG&E first reached a settlement agreement with the DOE in 2012. Pursuant to the settlement, yearly claims are submitted to the DOE. The annual administrative claims process was extended through the end of 2016 in an amendment to the settlement agreement with the DOE that was reached in 2013, and was extended through the end of 2019 in a 2016 amendment to the settlement. PG&E anticipates it will continue to collect annual payments under the administrative claims process through 2019. PG&E intends to pursue further extension of the annual administrative claims process and anticipates resolution of this issue in 2019. If the settlement is not extended, PG&E will be required to file a new lawsuit against DOE to recover the costs of spent fuel storage incurred beyond 2019.

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3 D.17-05-020, OP 10.

In D.14-08-032, PG&E's 2014 GRC Final Decision, the Commission determined that for the period 2014-2016 DOE litigation settlement proceeds net of outside legal costs should be refunded to customers with 28 percent attributable to HBPP refunded through the Nuclear Decommissioning Adjustment Mechanism (NDAM) and 72 percent attributable to DCPP refunded through the Utility Generation Balancing Account (UGBA). Claims proceeds are to be credited to the Department of Energy Litigation Balancing Account (DOELBA) as received, and transferred to the UGBA and NDAM on January 1 of the following year. D.17-05-013 extended this ratemaking methodology for the 2017-2019 period.

PG&E reported on settlement and refund amounts through 2014 in the 2015 NDCTP. Tables 6-1 and 6-2 identify all DOE payments received since 2015, the allocation of the settlement and claims payments to UGBA and NDAM and all refunds provided to customers during 2015-2017.

TABLE 6-1
AMOUNTS RECEIVED FROM DOE 2015-2017

Line No.	Claim 4 (Jun 2014 – May 2015)	Claim 5 (June 2015 – May 2016)	Claim 6 (June 2016 – May 2017)	Total Refund
1	$28,088,833	$14,915,322	$28,876,560	$71,880,715

TABLE 6-2
ALLOCATION OF AMOUNTS RECEIVED FROM DOE
RETURNED TO CUSTOMERS

Line No.		Claim 4 (Jan 2014 – May 2015)	Claim 5 (June 2015 – May 2016)	Claim 6 (June 2016 – May 2017)	Total Refund
1	Humboldt-Attributable	$7,864,873	$4,176,290	$8,085,436	$20,126,560
2	Diablo Canyon-Attributable	20,223,959	10,739,031	20,791,123	51,574,114
3	Total Refund	$28,088,833	$214,915,322	$28,876,560	$71,880,715

PG&E submitted its most recent claim of approximately $25 million, covering costs incurred from June 2017 – May 2018 on October 31, 2018.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

DIABLO CANYON POWER PLANT COMPLETED PROJECT

REASONABLENESS REVIEW

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
DIABLO CANYON POWER PLANT COMPLETED PROJECT REASONABLENESS REVIEW

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
DIABLO CANYON POWER PLANT COMPLETED PROJECT REASONABLENESS REVIEW

A. Introduction

The purpose of this chapter is to describe how Pacific Gas and Electric Company (PG&E) will track actual Diablo Canyon Power Plant (DCPP) decommissioning expenses in order to present completed projects for reasonableness review. PG&E proposes to use a Milestone Framework which breaks decommissioning work into specific milestones with specified scopes of work, cost estimates and schedules. PG&E will also maintain a Decision Log with a written record of key decisions impacting the cost, scope, or timing of a milestone.

B. Milestone Framework

The DCPP Decommissioning Cost Estimate (DCE) provides PG&E's forecast of decommissioning costs and schedule, which are reviewed for reasonableness upon completion of scopes of work in subsequent NDCTPs. Since this DCE is a new and site-specific estimate, the California Public Utilities Commission (Commission) has directed PG&E to develop a cost accounting system for DCPP that will facilitate tracking decommissioning expenses by major subprojects; allow for comparison to previously approved estimates of activities, costs, and schedules; and require written record of key decisions about cost, scope, or timing of a major project or activity (i.e., varies by plus or minus 10 percent).[1]

PG&E proposes to adopt a milestone framework similar to the approach proposed for the San Onofre Nuclear Generating Station. The DCPP milestone framework allocates decommissioning work into 19 milestones. PG&E will track

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[1] Decision 17-05-020, Ordering Paragraphs 3 and 4.

decommissioning expenses by milestone, which will readily enable a comparison of actual costs and schedule to previously approved estimates.[2]

PG&E developed the DCE using three major cost categories (License Termination, Spent Fuel Management and Site Restoration). By contrast, the Milestone Framework groups logical scopes of work together for reasonableness review.

Table 7-1 sets out the Milestones, each with identified subprojects. Subject to Commission review in subsequent NDCTPs, PG&E proposes that Milestones may be modified to allow for (1) moving activities from one major subproject to another; (2) adding new activities; and (3) adjusting the proposed decommissioning schedule.

2 PG&E based this DCE on a physical decommissioning plan. However, while the cost estimate and schedule will remain relevant for comparison purposes, it can be expected that as decommissioning approaches, PG&E will make changes and improvements, and this DCE does not represent a commitment to perform decommissioning work exactly as presented in the DCE.

TABLE 7-1
DCPP DECOMMISSIONING REASONABLENESS REVIEW MILESTONES

ID	Scope Description	Total EAC (2017$)
Unassigned Costs		
1	**Program Management, Oversight, and Fees**	**$1,462,045**
1.01	Staffing	$723,557
1.02	Severance	$155,429
1.03	Energy	$68,541
1.04	Insurance	$27,932
1.05	Property Tax	$40,211
1.06	NRC Fees / Reviews	$68,096
1.07	Association/Industry Fees	$8,055
1.08	Facility Maintenance	$21,654
1.09	Water Management	$72,734
1.10	Permits	$57,872
1.11	Future Land Use	$12,361
1.12	Spent Fuel Management Plan	$60,062
1.13	License Termination Plan	$14,207
1.14	Site Characterization	$15,013
1.15	Emergency Planning - Senate Bill 1090	$44,468
1.16	Emergency Planning	$27,513
1.17	Consumables	$38,209
1.18	Public Outreach & Stakeholder Engagement	$6,131
2	**Security Operations**	**$560,686**
2.01	Security Staffing	$542,064
2.02	Other Security Related Costs	$18,622
3	**Waste/Transportation/Material Management (Excluding: Breakwater, RPV/RVI Segmentation, & Large Component Removal)**	**$855,211**
3.01	Waste & Transportation Management	$125,716
3.02	Transportation	$108,309
3.03	Disposal	$585,525
3.04	Material Management	$51,808
3.05	Asset Recovery	-$53,647
3.06	GTCC Disposal	$37,500

TABLE 7-1
DCPP DECOMMISSIONING REASONABLENESS REVIEW MILESTONES
(CONTINUED)

ID	Scope Description	Total EAC (2017$)
Discrete Costs		
4	**Power Block Modifications**	**$80,707**
4.01	U1 Spent Fuel Pool Island	$6,680
4.02	U2 Spent Fuel Pool Island	$6,090
4.03	Install 230kV Baywood Feed	$17,338
4.04	U1 Cold and Dark	$18,692
4.05	U2 Cold and Dark	$18,692
4.06	Security Modifications	$13,216
5	**Site Infrastructure**	**$140,972**
5.01	Offsite Infrastructure	$29,411
5.02	Road Improvements	$16,543
5.03	Facility Construction	$28,742
5.04	Existing Building and Structure Modifications	$20,481
5.05	ISFSI Security Building Construction	$14,151
5.06	ISFSI Pad Expansion for GTCC Storage	$14,235
5.07	Project Oversight and Support	$17,410
6	**Large Component Removal**	**$166,370**
6.01	Legacy Steam Generators	$45,872
6.02	Legacy Rx Heads	$3,592
6.03	Steam Generators	$78,506
6.04	Reactor Heads	$4,614
6.05	Reactor Coolant Pumps	$9,361
6.06	Pressurizers	$4,215
6.07	Manipulators	$1,024
6.08	Generators and Exciters	$592
6.09	Main Turbines	$1,633
6.10	Diesel Generators	$728
6.11	Other Turbine Building Components	$5,387
6.12	Large Access Penetrations	$329
6.13	Project Oversight and Support	$10,517
7	**Reactor/Internals Segmentation**	**$332,341**
7.01	U1 Internals Segmentation	$17,308
7.02	U1 Reactor Segmentation	$10,165
7.03	U2 Internals Segmentation	$17,136
7.04	U2 Reactor Segmentation	$8,353
7.05	Waste & Transportation	$191,129
7.06	Project Oversight and Support	$36,417
7.07	Specialty Equipment	$51,833

TABLE 7-1
DCPP DECOMMISSIONING REASONABLENESS REVIEW MILESTONES
(CONTINUED)

ID	Scope Description	Total EAC (2017$)
8	**Spent Fuel transfer to ISFSI**	**$235,541**
8.01	SNF and GTCC Cask Procurement	$181,039
8.02	U1 Spent Fuel transfer to ISFSI	$27,552
8.03	U2 Spent Fuel transfer to ISFSI	$21,003
8.04	U1 GTCC Transfer to ISFSI	$3,574
8.05	U2 GTCC Transfer to ISFSI	$2,374
9	**Turbine Bldg**	**$68,667**
9.01	U1 Decontamination	$20,500
9.02	U1 System & Area Closure	$6,744
9.03	U1 Demolition	$5,635
9.04	U2 Decontamination	$18,630
9.05	U2 System & Area Closure	$10,871
9.06	U2 Demolition	$6,287
10	**Aux Building**	**$92,122**
10.01	U1 Decontamination	$2,969
10.02	U1 System & Area Closure	$33,998
10.03	U1 Demolition	$11,228
10.04	U2 Decontamination	$1,921
10.05	U2 System & Area Closure	$30,951
10.06	U2 Demolition	$11,055
11	**Containment**	**$121,012**
11.01	U1 Decontamination	$8,375
11.02	U1 System & Area Closure	$33,407
11.03	U1 Demolition	$19,283
11.04	U2 Decontamination	$6,540
11.05	U2 System & Area Closure	$33,888
11.06	U2 Demolition	$19,519
12	**Fuel Handling Building**	**$48,627**
12.01	U1 Decontamination	$2,013
12.02	U1 System & Area Closure	$14,905
12.03	U1 Demolition	$6,982
12.04	U2 Decontamination	$1,953
12.05	U2 System & Area Closure	$19,040
12.06	U2 Demolition	$3,735
14	**Balance of Site**	**$80,702**
14.01	Decontamination	$11,011
14.02	System & Area Closure	$14,163
14.03	Demolition	$55,528

TABLE 7-1
DCPP DECOMMISSIONING REASONABLENESS REVIEW MILESTONES
(CONTINUED)

ID	Scope Description	Total EAC (2017$)
15	**Intake Structure**	**$41,654**
15.01	System Area Closure	$6,486
15.02	Coffer Dam	$14,364
15.03	Demolition	$20,804
16	**Discharge Structure**	**$15,122**
16.01	Discharge Piping Decon	$570
16.02	Coffer Dam	$7,261
16.03	Demolition	$2,696
16.04	System Area Closure	$4,595
17	**Breakwater**	**$286,326**
17.01	Demolition	$138,910
17.02	Transportation	$129,249
17.03	Disposal Cost	$18,166
18	**Non-ISFSI Site Restoration**	**$135,075**
18.01	Utilities and Structures Demo	$31,549
18.02	Soil Remediation	$4,145
18.03	Final Site Survey	$40,263
18.04	Grading and Landscaping	$59,118
19	**Spent Fuel transfer to DOE**	**$24,258**
19.01	U1 Spent Fuel Transfer to DOE	$6,889
19.02	U2 Spent Fuel Transfer to DOE	$16,376
19.03	GTCC Transfer to Offsite Facility	$993
20	**ISFSI Demolition and Site Restoration**	**$54,956**
20.01	Utilities and Structures Demo	$23,671
20.02	Soil Remediation	$2,048
20.03	Final Site Survey	$1,915
20.04	Grading and Landscaping	$27,322
	GRAND TOTAL	$4,802,395

Below are summaries for each DCPP decommissioning Milestone:

1. Program Management, Oversight, & Fees: This category includes general staff support and oversight, severance costs, metered energy usage, water and facility management, taxes, insurance fees, regulatory and industry fees, public engagement, radiological characterization, license termination preparation, emergency planning staffing and fees, and consumables. These costs are necessary decommissioning costs that are unassigned, and not associated with a discrete scope of work. Costs in this unassigned category will be submitted for reasonableness reviews at specified times in the decommissioning project lifecycle which represent a significant change in the staffing profile and associated costs.

2. Security Operations: This category includes the general security staffing and associated departmental costs for the duration of the decommissioning project. The security modification costs are excluded from this category and are included in Power Block Modifications. Costs in this unassigned category will be submitted for reasonableness reviews at specified times in the decommissioning project lifecycle which represent a significant change in the staffing profile and associated costs.
3. Waste/Transportation: This category includes costs for transportation and disposal of all waste classifications excluding those associated with Breakwater Removal, Reactor/Internals Segmentation, and Large Component removal since waste costs associated with those scopes of work are easily segregated and can be allocated to their discrete projects. This category also includes material management which covers the management and sale of remaining assets. Costs in this unassigned category will be submitted for reasonableness reviews at specified times in the decommissioning project lifecycle which represent a significant change in the staffing profile and associated costs.
4. Power Block Modifications: This category includes the spent fuel pool island, cold and dark, and security modifications. These modifications are all implemented early in the project lifecycle and will allow PG&E to either reduce staffing levels or enhance the ability to safely execute decommissioning.
5. Site Infrastructure: This category includes onsite and offsite infrastructure improvements required to complete decommissioning.
6. Large Component Removal: This category includes removal of steam generators, reactor heads, reactor coolant pumps, main generator, main turbine, and other various large components that must be removed prior to demolition. This category also includes the transportation and disposal costs of the components.
7. Reactor/Internals Segmentation: This category includes the reactor pressure vessel and reactor internals segmentation along with the transportation and disposal costs. This scope of work is very specialized and includes the fabrication of custom tooling.

8. Spent Fuel Transfer to ISFSI: This category includes the procurement of storage canisters/casks for both GTCC and spent fuel, the costs of loading spent fuel into casks, and transferring of all casks from the fuel handling building to the ISFSI pad. The loading of GTCC waste into casks can be found in the Reactor/Internals Segmentation scope.
9. Turbine Building Removal: This category includes decontamination, system and area closure, and demolition of the Unit 1 and Unit 2 turbine building.
10. Aux Building Removal: This category includes decontamination, system and area closure, and demolition of the Unit 1 and Unit 2 auxiliary building.
11. Containment Removal: This category includes decontamination, system and area closure, and demolition of the Unit 1 and Unit 2 containment buildings.
12. Fuel Handling Building Removal: This category includes decontamination, system and area closure, and demolition of the Unit 1 and Unit 2 fuel handling building.
13. Milestone 13 originally included the scope to remove the radiological waste laundry facility. This scope has been rolled into the Balance of Site Removal scope due to the negligible impact to cost and schedule. All costs previously associated with Milestone 13 are incorporated into Milestone 14.
14. Balance of Site Removal: This category includes decontamination, system and area closure, and demolition of all remaining common and unit specific structures.
15. Intake Structure Removal: This category includes installing of a coffer dam inside the breakwater lagoon, system and area closure, removal of the intake structure, and removal of the coffer dam.
16. Discharge Structure Removal: This category includes installing of a coffer dam around the discharge structure, decontamination, system and area closure, removal of the discharge structure, and removal of the coffer dam.
17. Breakwater Removal: This category includes demolition, transportation, and disposal of the East and West breakwaters.
18. Non-ISFSI Site Restoration: This category includes underground utility and structure demolition, soil remediation, final site survey, and final grading, landscaping, and re-vegetation of the non-ISFSI portion of the site.
19. Spent Fuel Transfer to DOE: This category includes the transfer of spent fuel and GTCC casks to the Department of Energy.

20. ISFSI Demolition and Site Restoration: This category includes underground utility and structure demolition, soil remediation, final site survey, and final grading, landscaping, and re-vegetation of the ISFSI portion of the site.

C. Discrete and Unassigned Cost Milestones

Decommissioning costs include both discrete and unassigned costs. Discrete costs are those costs that can be directly attributed to a project with identified start and completion criteria, such as Power Block Modifications and Large Component Removal. Costs included in each Discrete Milestone include the resources necessary to complete the Project such as equipment, materials, and the non-PG&E resources required to execute the Project throughout the decommissioning project lifecycle. PG&E ensured that the Unassigned Cost Milestones only include the oversight required for the overall decommissioning project and do not include costs which may be attributed to a discrete scope.

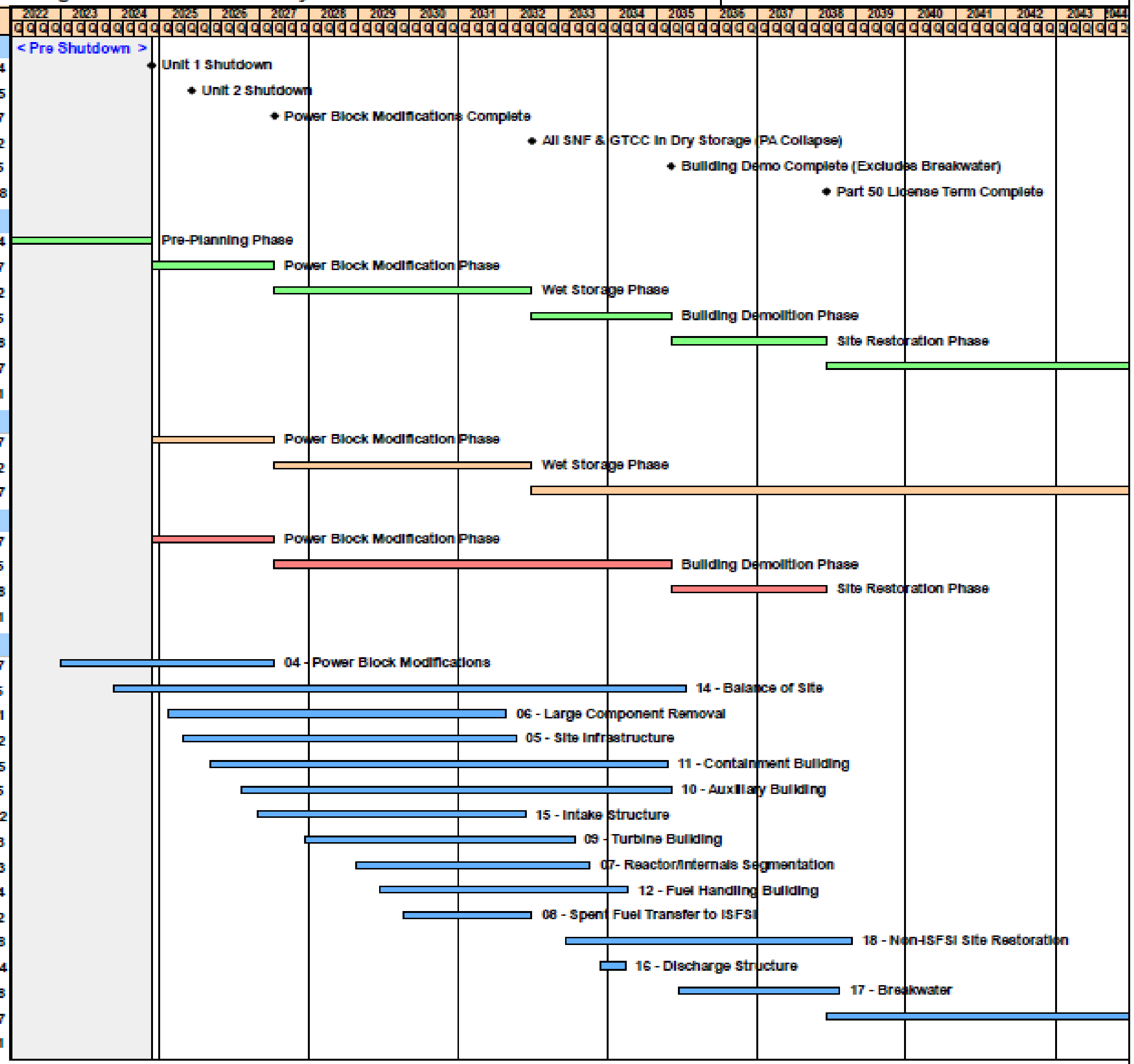
Unassigned cost Milestones include: (1) Program Management, Oversight, and Fees; (2) Security Operations; and (3) Waste/Transportation/Material Management (excluding Reactor/Internals Segmentation, Large Component Removal, and Breakwaters). These Milestones include necessary decommissioning expenses not attributed to a specific subproject and support multiple scopes of discrete work that occur at varying time periods, as well as general project oversight. For example, waste, transportation, and material management costs are considered to be unassigned because the final handling and transportation of a waste shipment will likely include multiple scopes of work (e.g., Turbine Building decontamination, Fuel Handling Building system area closure, and building demolition work will produce waste to be handled, transported, and shipped concurrently). This is not the case with all waste however; waste associated with Large Component Removal and Reactor/Internals Segmentation will be easily segregated from the general waste streams because the components are large or highly irradiated and require custom transportation and disposal. The Breakwater waste and transportation will also be easily segregated because the waste will be taken to a unique location for drying before transportation to a disposal facility. For this reason, waste and transportation for Large Component Removal, Reactor/Internals Segmentation, and Breakwater are not included in the Waste/Transportation/Material Management unassigned cost.

Unassigned Milestones will be submitted for reasonableness reviews at the conclusion of certain identified decommissioning phases. Each phase represents a significant change in the staffing profile and associated costs. For these costs, there is no easily identifiable completion date; thus, the Unassigned Costs are presented for reasonableness based on completion of major decommissioning phases as shown in Figure 7-1 and defined below. These phases are appropriate timeframes to evaluate reasonableness of Unassigned Costs as they reflect when either major regulatory requirement changes occur (e.g., significant decreases in staffing) or major scopes of work are completed (e.g., all building demo is completed).

FIGURE 7-1
DCPP DECOMMISSIONING MILESTONE SCHEDULE

DCPP Decommissioning and Demolition P6 Layout — Printed On 13-Nov-18

#	Activity Name	Start	Finish
1	**Milestones**		
2	Unit 1 Shutdown		02-Nov-24
3	Unit 2 Shutdown		26-Aug-25
4	Power Block Modifications Complete		27-Apr-27
5	All SNF & GTCC In Dry Storage (PA Collapse)		24-Jun-32
6	Building Demo Complete (Excludes Breakwater)		11-Apr-35
7	Part 50 License Term Complete		27-May-38
8	**Staffing & Administrative**		
9	Pre-Planning Phase	01-Jan-22	02-Nov-24
10	Power Block Modification Phase	04-Nov-24	27-Apr-27
11	Wet Storage Phase	28-Apr-27	24-Jun-32
12	Building Demolition Phase	25-Jun-32	11-Apr-35
13	Site Restoration Phase	12-Apr-35	07-Dec-38
14	ISFSI Operations Phase	28-May-38	01-Aug-67
15	ISFSI Restoration Phase	02-Aug-67	02-Feb-71
16	**Security & Operations**		
17	Power Block Modification Phase	04-Nov-24	27-Apr-27
18	Wet Storage Phase	28-Apr-27	24-Jun-32
19	ISFSI Operations	25-Jun-32	01-Aug-67
20	**Waste / Transportation**		
21	Power Block Modification Phase	04-Nov-24	27-Apr-27
22	Building Demolition Phase	28-Apr-27	11-Apr-35
23	Site Restoration Phase	12-Apr-35	07-Dec-38
24	ISFSI Restoration Phase	02-Aug-67	02-Feb-71
25	**Discrete Scope**		
26	04 - Power Block Modifications	03-Jan-23	27-Apr-27
27	14 - Balance of Site	25-Jan-24	31-Jul-35
28	06 - Large Component Removal	04-Mar-25	23-Dec-31
29	05 - Site Infrastructure	23-Jun-25	02-Mar-32
30	11 - Containment Building	08-Jan-26	14-Mar-35
31	10 - Auxiliary Building	20-Aug-26	11-Apr-35
32	15 - Intake Structure	23-Dec-26	06-May-32
33	09 - Turbine Building	01-Dec-27	27-Apr-33
34	07- Reactor/Internals Segmentation	18-Dec-28	29-Aug-33
35	12 - Fuel Handling Building	31-May-29	06-Jun-34
36	08 - Spent Fuel Transfer to ISFSI	28-Nov-29	24-Jun-32
37	18 - Non-ISFSI Site Restoration	02-Mar-33	07-Dec-38
38	16 - Discharge Structure	09-Nov-33	16-May-34
39	17 - Breakwater	11-Jun-35	01-Sep-38
40	19 - Spent Fuel transfer to DOE	01-Jun-38	09-Aug-67
41	20 - ISFSI Demolition & Site Restoration	02-Aug-67	29-Jan-71



Blue Line Schedule — 1 of 1

- Pre-Planning Phase: The pre-shutdown planning time period from 2016 until Unit 1 shutdown in early November 2025. A significant severance in non-security staff will occur at this point in time.
- Power Block Modifications Phase: The period after Unit 1 shutdown up until the Cold and Dark, Spent Fuel Pool Island, and Security modifications are complete. The completion of these modifications will drive a significant drop in security staffing levels.
- Wet Storage Phase: The period from completion of power block modifications to the completion of spent fuel transfers to ISFSI. Completion of this phase drives significant reductions in staffing related to management of wet fuel and security related to the protected area which will be eliminated (ISFSI protected area still remains).
- Building Demolition Phase: The period from completion of spent fuel transfers to the completion of all building demolition, excluding the breakwater. The completion of this period represents closure of a large portion of the non-radiological waste and nearly all radiological waste.
- Site Restoration Phase: The period from the building demolition phase to the completion of all non-ISFSI site demolition and restoration. This milestone signifies completion of the decommissioning project, excluding the ISFSI demolition which will not occur for another 30 years. This phase represents completion of the breakwater demolition which is a large portion of the non-radiological waste on site, and the final step down in staffing.
- ISFSI Operations Phase: The period between decommissioning of the plant site and the start of ISFSI demolition. This phase contains only security staffing at ISFSI and transfer of spent fuel and GTCC to the DOE. Completion of this phase represents the final step down in security staffing.
- ISFSI Restoration Phase: The period from which all spent fuel and GTCC are removed from ISFSI and the entire site is restored. This phase represents completion of decommissioning and project closure.

D. Review of Completed Projects

Costs and activities will be presented for reasonableness review in the Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) following the completion of a discrete Milestone or, for unassigned Milestones, following completion of a defined major decommissioning phase.

To provide a predictable timeline for review of DCPP decommissioning activities and costs; Table 7-2 identifies anticipated completion dates and the NDCTP in which Milestones are projected to be reviewed.

TABLE 7-2
EXPECTED DCPP DECOMMISSIONING MILESTONE REASONABLENESS REVIEW SCHEDULE

2024 NDCTP	Completion Date	Costs (2017$)
(1) Program Management, Oversight, Fees — Pre-Planning Phase	2-Nov-24	$154,837
2027 NDCTP		
(4) Power Block Modifications Complete	27-Apr-27	$80,706
(1) Program Management, Oversight, Fees — Power Block Mods Phase	27-Apr-27	$325,433
(2) Security Operations — Power Block Mods Phase	27-Apr-27	$95,933
(3) Waste/Transportation/Material Management — Power Block Mods Phase	27-Apr-27	$20,179
2033 NDCTP		
(6) Large Component Removal & Waste Disposal Complete	23-Dec-31	$166,370
(15) Intake Demolition Complete	6-May-32	$41,654
(8) Spent Fuel & GTCC Waste Transfers to ISFSI Complete	24-Jun-32	$235,525
(1) Program Management, Oversight, Fees — Wet Storage Phase	24-Jun-32	$409,043
(2) Security Operations — Wet Storage Phase	24-Jun-32	$215,266
(5) Site Infrastructure Complete	7-Oct-32	$140,972
(9) Turbine Building Demolition Complete	27-Apr-33	$68,667
(7) Reactor/Internals Segmentation & Disposal Complete	29-Aug-33	$332,341
2036 NDCTP		
(16) Discharge Structure Demolition Complete	16-May-34	$15,122
(12) Fuel Handling Building Demolitions Complete	6-Jun-34	$48,627
(10) Aux Building Demolition Complete	13-Jun-34	$92,122
(11) Containment Building Demolitions Complete	14-Mar-35	$121,012
(1) Program Management, Oversight, Fees — Building Demo Phase	14-Mar-35	$202,796
(3) Waste/Transportation/Material Management — Building Demo Phase	14-Mar-35	$607,270
2039 NDCTP		
(14) Balance of Site Demolitions Complete	11-Mar-38	$80,702
(17) Breakwater Demolition Complete	9-Sep-38	$286,326
(18) Non-ISFSI Site Restoration Complete	7-Dec-38	$135,075
(1) Program Management, Oversight, Fees — Site Restoration Phase	7-Dec-38	$152,262
(3) Waste/Transportation/Material Management — Site Restoration Phase	7-Dec-38	$164,966
2069 NDCTP		
(1) Program Management, Oversight, Fees — ISFSI Operations Phase	9-Aug-67	$188,622
(2) Security Operations — ISFSI Operations Phase	9-Aug-67	$249,487
(19) Spent Fuel & GTCC Waste Transfers to DOE Complete	9-Aug-67	$24,258
2072 NDCTP		
(1) Program Management, Oversight, Fees — ISFSI Restoration Phase	29-Jan-71	$29,068
(20) ISFSI Demolition & Restoration Complete	29-Jan-71	$54,956
(3) Waste/Transportation/Material Management — ISFSI Restoration Phase	29-Jan-71	$62,797

E. Comparison of Completed Work to Prior Estimate

At the Commission's directive, in July 2017, PG&E met with representatives from the Commission's Energy Division and interested parties. PG&E provided a cost comparison in initial draft format intended to provide sufficient detail to compare actual costs to previously approved estimates. PG&E obtained concurrence from the participating parties on the overall cost comparison table format. Table 7-3 sets forth PG&E's current cost comparison table format, which has been updated to reflect the Milestones PG&E developed. This reporting format will be used for the first DCPP Decommissioning reasonableness review in 2024. The Pre-Planning phase of Program Management, Oversight, and Fees will be presented for reasonableness in the 2024 NDCTP, represented by the yellow highlighted area in Table 7-3.

TABLE 7-3
DCPP MILESTONE COMPARISON TO TWO PRIOR NDCTP ESTIMATES

ID	Phase	Scope Description	2018 A Approved DCE	2021 B Approved DCE	2024 NDCTP C Nominal Spend through 2023	2024 NDCTP D Estimate to Complete	2024 NDCTP E Estimate at Completion	F Delta from 2021 NDCTP (E - B)
						(in thousands)		
1	**Program Management, Oversight, and Fees**		**$1,462,062**					
	Pre-Planning		**$154,837**					
		1.01 Staffing	$113,071					
		1.06 NRC Fees / Reviews	$13,576					
		1.10 Permits	$19,454					
		1.11 Future Land Use	$7,229					
		1.12 Spent Fuel Management Plan	$57					
		1.18 Public Outreach & Stakeholder Engagement	$1,450					
	Power Block Mods		$325,433					
	Wet Storage		$409,043					
	Building Demo		$202,796					
	Site Restoration		$152,262					
	ISFSI Operations		$188,622					
	ISFSI Restoration		$29,068					
2	**Security Operations**		**$560,686**					
	Power Block Mods		$95,933					
	Wet Storage		$215,266					
	ISFSI Operations		$249,487					
3	**Waste/Transportation/Material Management (Excluding: Breakwater, RPV/RVI Segmentation, & Large Component Removal)**		**$855,211**					
	Power Block Mods		$20,179					
	Building Demo		$607,269					
	Site Restoration		$164,966					
	ISFSI Restoration		$62,797					
4	**Power Block Modifications**		**$80,707**					
		4.01 U1 Spent Fuel Pool Island	$6,680					
		4.02 U2 Spent Fuel Pool Island	$6,090					
		4.03 Install 230kV Baywood Feed	$17,338					

TABLE 7-3
DCPP MILESTONE COMPARISON TO TWO PRIOR NDCTP ESTIMATES
(CONTINUED)

			2018	2021	2024 NDCTP			
			A	B	C	D	E	F
ID	Phase	Scope Description	Approved DCE	Approved DCE	Nominal Spend through 2023	Estimate to Complete	Estimate at Completion	Delta from 2021 NDCTP (E - B)
	4.04	U1 Cold and Dark	$18,692					
	4.05	U2 Cold and Dark	$18,692					
	4.06	Security Modifications	$13,216					
5	**Site Infrastructure**		**$140,972**					
	5.01	Offsite Infrastructure	$29,411					
	5.02	Road Improvements	$16,543					
	5.03	Facility Construction	$28,742					
	5.04	Existing Building and Structure Modifications	$20,481					
	5.05	ISFSI Security Building Construction	$14,151					
	5.06	ISFSI Pad Expansion for GTCC Storage	$14,235					
	5.07	ProjectOversight and Support	$17,410					
6	**Large Component Removal**		**$166,370**					
	6.01	Legacy Steam Generators	$45,872					
	6.02	Legacy Rx Heads	$3,592					
	6.03	Steam Generators	$78,506					
	6.04	Reactor Heads	$4,614					
	6.05	Reactor Coolant Pumps	$9,361					
	6.06	Pressurizers	$4,215					
	6.07	Manipulators	$1,024					
	6.08	Generators and Exciters	$592					
	6.09	Main Turbines	$1,633					
	6.10	Diesel Generators	$728					
	6.11	Other Turbine Building Components	$5,387					
	6.12	Large Access Penetrations	$329					
	6.13	ProjectOversight and Support	$10,517					
7	**Reactor/Internals Segmentation**		**$332,341**					
	7.01	U1 Internals Segmentation	$17,308					
	7.02	U1 Reactor Segmentation	$10,165					

TABLE 7-3
DCPP MILESTONE COMPARISON TO TWO PRIOR NDCTP ESTIMATES
(CONTINUED)

				2018	2021	2024 NDCTP			
				A	B	C	D	E	F
ID	Phase		Scope Description	Approved DCE	Approved DCE	Nominal Spend through 2023	Estimate to Complete	Estimate at Completion	Delta from 2021 NDCTP (E - B)
		7.03	U2 Internals Segmentation	$17,136					
		7.04	U2 Reactor Segmentation	$8,353					
		7.05	Waste & Transportation	$191,129					
		7.06	ProjectOversight and Support	$36,417					
		7.07	Specialty Equipment	$51,833					
8	**Spent Fuel transfer to ISFSI**			**$235,525**					
		8.01	SNF and GTCC Cask Procurement	$181,039					
		8.02	U1 Spent Fuel tranfer to ISFSI	$27,537					
		8.03	U2 Spent Fuel tranfer to ISFSI	$21,001					
		8.04	U1 GTCC Transfer to ISFSI	$3,574					
		8.05	U2 GTCC Transfer to ISFSI	$2,374					
9	**Turbine Bldg**			**$68,667**					
		9.01	U1 Decontamination	$20,500					
		9.02	U1 System & Area Closure	$6,744					
		9.03	U1 Demolition	$5,635					
		9.04	U2 Decontamination	$18,630					
		9.05	U2 System & Area Closure	$10,871					
		9.06	U2 Demolition	$6,287					
10	**Aux Building**			**$92,122**					
		10.01	U1 Decontamination	$2,969					
		10.02	U1 System & Area Closure	$33,998					
		10.03	U1 Demolition	$11,228					
		10.04	U2 Decontamination	$1,921					
		10.05	U2 System & Area Closure	$30,951					
		10.06	U2 Demolition	$11,055					
11	**Containment**			**$121,012**					
		11.01	U1 Decontamination	$8,375					
		11.02	U1 System & Area Closure	$33,407					

TABLE 7-3
DCPP MILESTONE COMPARISON TO TWO PRIOR NDCTP ESTIMATES
(CONTINUED)

ID	Phase		Scope Description	2018 A Approved DCE	2021 B Approved DCE	2024 NDCTP C Nominal Spend through 2023	2024 NDCTP D Estimate to Complete	2024 NDCTP E Estimate at Completion	F Delta from 2021 NDCTP (E - B)
		11.03	U1 Demolition	$19,283					
		11.04	U2 Decontamination	$6,540					
		11.05	U2 System & Area Closure	$33,888					
		11.06	U2 Demolition	$19,519					
12	**Fuel Handling Building**			**$48,627**					
		12.01	U1 Decontamination	$2,013					
		12.02	U1 System & Area Closure	$14,905					
		12.03	U1 Demolition	$6,982					
		12.04	U2 Decontamination	$1,953					
		12.05	U2 System & Area Closure	$19,040					
		12.06	U2 Demolition	$3,735					
14	**Balance of Site**			**$80,702**					
		14.01	Decontamination	$11,011					
		14.02	System & Area Closure	$14,163					
		14.03	Demolition	$55,528					
15	**Intake Structure**			**$41,654**					
		15.01	System Area Closure	$6,486					
		15.02	Coffer Dam	$14,364					
		15.03	Demolition	$20,804					
16	**Discharge Structure**			**$15,122**					
		16.01	Discharge Piping Decon	$570					
		16.02	Coffer Dam	$7,261					
		16.03	Demolition	$2,696					
		16.04	System Area Closure	$4,595					
17	**Breakwater**			**$286,326**					
		17.01	Demolition	$138,910					
		17.02	Transportation	$129,249					

TABLE 7-3
DCPP MILESTONE COMPARISON TO TWO PRIOR NDCTP ESTIMATES
(CONTINUED)

			2018	2021	2024 NDCTP			
			A	B	C	D	E	F
ID	Phase	Scope Description	Approved DCE	Approved DCE	Nominal Spend through 2023	Estimate to Complete	Estimate at Completion	Delta from 2021 NDCTP (E - B)
	17.03	Disposal Cost	$18,166					
18	**Non-ISFSI Site Restoration**		**$135,075**					
	18.01	Utilities and Structures Demo	$31,549					
	18.02	Soil Remediation	$4,145					
	18.03	Final Site Survey	$40,263					
	18.04	Grading and Landscaping	$59,118					
19	**Spent Fuel transfer to DOE**		**$24,258**					
	19.01	U1 Spent Fuel Transfer to DOE	$6,889					
	19.02	U2 Spent Fuel Transfer to DOE	$16,376					
	19.03	GTCC Transfer to Offsite Facility	$993					
20	**ISFSI Demolition and Site Restoration**		**$54,956**					
	20.01	Utilities and Structures Demo	$23,671					
	20.02	Soil Remediation	$2,048					
	20.03	Final Site Survey	$1,915					
	20.04	Grading and Landscaping	$27,322					
	GRAND TOTAL		$4,802,395					

F. Decision Log

Commencing on the date of a final decision in the 2018 NDCTP adopting a site-specific DCE for DCPP, PG&E will maintain an ongoing Decision Log to track decisions relative to DCPP decommissioning activities. Since the current site-specific DCE was developed as a ground-up evaluation without reference to the prior DCE, PG&E made no decisions with respect to the prior DCE. The Decision Log will include any decisions pertaining to cost, scope, or timing that could affect a milestone by plus or minus more than 10 percent.

The Decision Log will identify:

- Description of the decision;
- Date decision was made;
- Decision-maker;
- Factors considered; and
- Alternatives considered.

G. Conclusion

PG&E requests that the Commission adopt the Milestone framework set forth in this Chapter for purposes of reviewing actual DCPP decommissioning expenditures.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

HUMBOLDT BAY POWER PLANT UNIT 3 UPDATED NUCLEAR DECOMMISSIONING COST ESTIMATE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
HUMBOLDT BAY POWER PLANT UNIT 3 UPDATED NUCLEAR DECOMMISSIONING COST ESTIMATE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
HUMBOLDT BAY POWER PLANT UNIT 3 UPDATED NUCLEAR DECOMMISSIONING COST ESTIMATE

A. Introduction

The purpose of this chapter is to provide Pacific Gas and Electric Company's (PG&E) updated estimate of the remaining activities, cost and schedule to complete decommissioning and Nuclear Regulatory Commission (NRC) license termination at Humboldt Bay Power Plant Unit 3 (HBPP). Due to the advanced status of decommissioning and the limited nature of revisions to the approved estimate, the 2018 HBPP Decommissioning Cost Estimate (HBPP DCE) updates, rather than replaces, the 2015 HBPP Decommissioning Project Report (2015 DPR). The HBPP DCE is provided as Chapter 8, Attachment A and the 2015 DPR is provided as Chapter 8, Attachment B.

B. Summary

The HBPP DCE covers the period from January 2019 through 2033, including: completion of final site restoration (FSR); HBPP radiological decommissioning; termination of the HBPP 10 CFR Part 50 license; management of Spent Nuclear Fuel (SNF)/Greater-Than-Class-C (GTCC) waste in the HBPP Independent Spent Fuel Storage Installation (ISFSI); HBPP ISFSI decommissioning after the SNF/GTCC waste has been moved to an off-site facility; and FSR and termination of the ISFSI 10 Code of Federal Regulations (CFR) Part 72 license.

In the 2015 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), the California Public Utilities Commission (Commission) approved PG&E's HBPP DCE of $1,095.4 million (nominal/2018$).[1] During the period 2015 through 2018, the Civil Works Contractor (CWC) completed demolition of the majority of remaining structures and infrastructure, and the FSR for the Part 50 license is scheduled to be completed in 2019. After more than three decades in Safe Storage (SAFSTOR) and nine years of decontamination and

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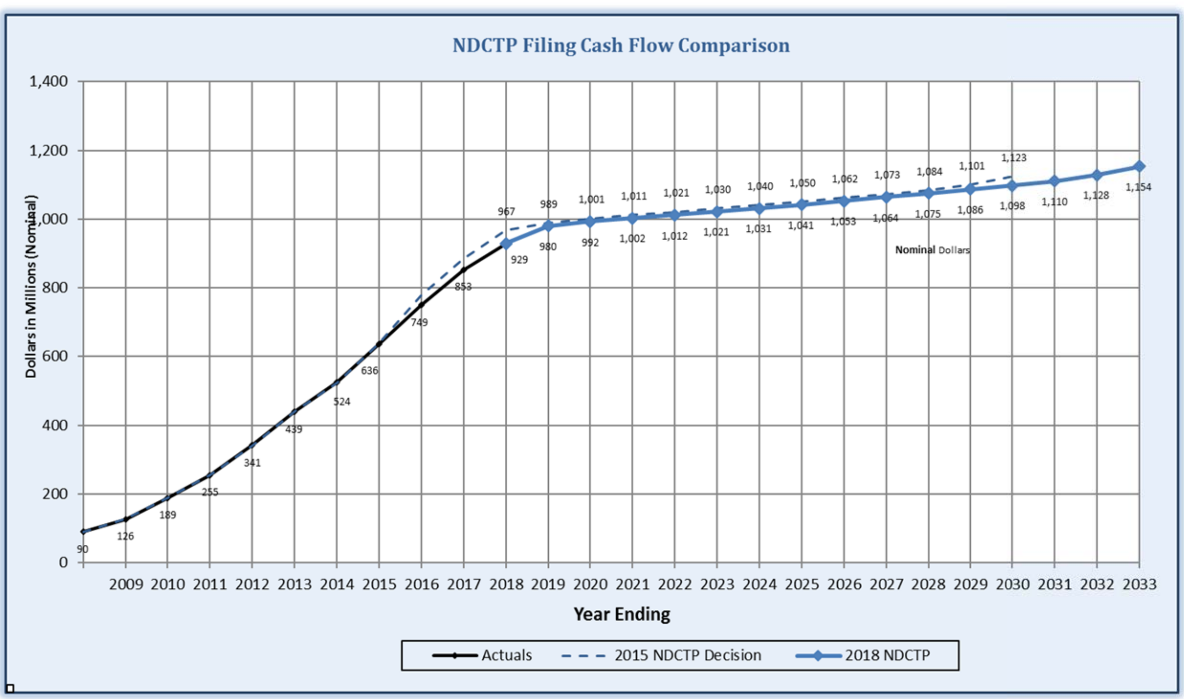
[1] Since HBPP completed a major phase of decommissioning in 2018 and the HBPP Reasonableness Report covers activities through 2018, the HBPP DCE is based on 2018$. Unless otherwise stated, costs herein are in 2018$.

dismantlement, the site is configured and ready for Final Status Survey (FSS), which is also planned to be completed in 2019.

In preparation for its 2018 NDCTP, PG&E reviewed its previously-approved estimate, work completed since the 2015 NDCTP and anticipated remaining work, schedule and costs. PG&E has concluded that there is no change from the forecast approved in the 2015 NDCTP, other than: (1) a decrease of $9.0 million due to cost savings of approximately $7 million in Canal Remediation Disposal and $2 million in EPC Services; and (2) an increase of $25.1 million related to the assumption that PG&E will incur an additional three (3) years of spent fuel management costs based on an assumed delay from 2028 to 2031 in DOE commencing pick up of SNF/GTCC waste.[2] The updated total HBPP decommissioning cost is $1,111.5 million (nominal/2018$), with a cost to complete as shown in Table 8-1 as of January 1, 2019 of $182.5 million, resulting in an increase of $16.1 million from the forecast approved in the 2015 NDCTP.

FIGURE 8-1
NDCTP FILING CASH FLOW COMPARISON



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2 The basis for this assumption is provided in Chapter 6, Section D.

A detailed cost breakdown and comparison to the 2012 and 2015 NDCTP estimates is provided in Table 8-2: HBPP Decommissioning Cost Breakdown.

C. NRC License Termination

PG&E has two NRC-issued licenses for the HBPP site: one issued under 10 CFR Part 50 pertaining to HBPP Unit 3, and the other issued under 10 CFR Part 72 pertaining to the operation of the HBPP ISFSI for the storage of SNF and GTCC waste from the operation of Unit 3.

1. Part 50 License Termination Plan

The HBPP Part 50 License Termination Plan (LTP) was approved by the NRC in May 2015 (ADAMS ML15090A339). The LTP includes site characterization data; a description of the remaining dismantling activities; plans for site remediation; procedures for the final radiation survey; and designation of the end use of the HBPP site. It also includes the final survey plan, which identifies the radiological surveys to be performed once the remediation activities are completed. The final survey plan was developed using the guidance provided in the "Multi-Agency Radiation Survey and Site Investigation Manual." Surveys performed under this guidance provide a high degree of confidence that applicable NRC criteria are satisfied.

The LTP is an appendix to the Defueled Safety Analysis Report and is required by NRC regulation to be updated and submitted to the NRC every two years. The updated LTP was provided to the NRC in February 2018 (ML 18066A137).

Once the final survey data, final summary report, and license amendment request are submitted to the NRC in 2020, the agency will review and evaluate the information, perform an independent confirmation of radiological site conditions and decide whether the terminal radiation survey and associated documentation demonstrates that the facility complies with radiological release criteria. If so, it will terminate the HBPP 10 CFR Part 50 license.

2. ISFSI Operations and Demolition

Following the termination of the HBPP 10 CFR Part 50 license, the HBPP ISFSI will continue to be operated under the 10 CFR Part 72 license until all SNF and GTCC waste has been transferred to the Department of

Energy (DOE). For purposes of developing the HBPP DCE, PG&E assumes that the DOE will commence transferring SNF and GTCC waste casks from the HBPP ISFSI in 2031 and will complete transfer operations in 2032.

Because of delays with the pickup of SNF and GTCC waste from the HBPP ISFSI beyond the current 10 CFR Part 72 license termination date of 2022, PG&E prepared and submitted a License Renewal Application in July 2018. The application requests a forty-year extension, with an expiration date of November 2065.

Terminating the HB ISFSI 10 CFR Part 72 license will require preparation of an ISFSI LTP dismantlement of the ISFSI vault and any necessary remediation. PG&E will perform an FSS and complete FSR. The FSS documentation will be transmitted to the NRC with a License Amendment Request (LAR) for license termination. After the NRC determines that the ISFSI site remediation has been performed in accordance with the ISFSI LTP and the associated documentation demonstrates compliance with the plan, the NRC will terminate the 10 CFR Part 72 license.

D. Other Agency Approvals

While the NRC has the authority to terminate the HBPP 10 CFR Part 50 license, other agencies also have permitting authority over decommissioning activities. Some of these permits will expire unless renewed by PG&E, while other permits or permit requirements will continue in perpetuity. PG&E is consulting with regulatory agencies to terminate permits, where appropriate. Permit requirements that will remain after decommissioning completes consist of the Coastal Development Permits (CDP) for the ISFSI. The CDP (CDP E-05-001), related to the construction of the HBPP ISFSI, includes the following requirements that continue after decommissioning HBPP:

- Special Condition 1 – Monitoring Bluff Slopes: No less than every five years, PG&E shall monitor bluff slopes for sliding, ground movement and other motion. No later than June 30 of each subsequent fifth year, PG&E shall submit a report, prepared by a licensed Civil Engineering Geologist, to the California Coastal Commission (CCC), describing the results of the monitoring. If during any five-year period, monitoring shows any horizontal or vertical movement of the bluff slope or edge of two feet or greater, monitoring and reporting shall then be done on an annual basis, with the report as previously described being submitted no later than June 30 of each year. If during five consecutive annual monitoring periods, movement of the bluff slope and edge totals less than two feet, monitoring and reporting may return to a five-year schedule. PG&E shall notify the CCC Director immediately in the event of slope failure or movement, which may indicate imminent slope failure. If monitoring results for any reporting period indicate slope movement, which may require additional measures to protect the bluffs, PG&E shall submit a CDP application or request for an amendment.

- Special Condition 2 – Monitoring Shoreline Erosion: No less than every five years, PG&E shall conduct surveys of the shoreline and lower toe of the bluff of the ISFSI site. Surveys shall be conducted by a licensed Surveyor or Civil Engineer. Each survey shall be performed in the early spring, or as close to that time as is feasible, when the beach level is lowest, and the lower bluff face is most exposed. Each survey shall record the position of the lower toe of the bluff using conventional survey techniques (total station, rod and level, plane table, etc.), differential Global Positioning System, photogrammetry (with current ortho-rectified aerial photographs), by ground Light Detection and Ranging, or other comparable technique. Survey techniques used shall be consistent throughout the survey period or shall allow consistent comparison of yearly data. Survey measurements shall be accurate within 0.5 feet horizontally and 1.0 foot vertically. PG&E shall report the results of each survey to the CCC by June 30 of every fifth year. Each report shall include narrative and mapped analysis of the survey data, a determination of the average retreat rate for the full survey area and identification of any location(s) where the bluff change rate is more than two standard deviations from the average. Bluff change shall be calculated at 50-foot intervals or less, to determine the average retreat, the standard deviation and to identify areas of outlier retreat rates. If monitoring results for any survey indicate the development may be threatened by coastal erosion in less than five years, PG&E shall submit within sixty days of the annual survey report a CDP application or request for an amendment to this permit to relocate the ISFSI or other project components as needed.

- Special Condition 5 – Public Access:

  a) PG&E shall execute and have recorded against the parcel governed by the permit a deed restriction in a form and content acceptable to the CCC. The deed restriction shall establish an accessway based on the existing public use trail and shall extend along the shoreline from the western end of the power plant site near King Salmon Road to the rail line on the northern end of the power plant site. The accessway shall be no less than 20 feet wide at any point, as measured landward from the ordinary high-water mark. The deed restriction shall also reflect that this accessway will move with the shoreline; that is, the minimum dimensions of the accessway shall be maintained as the ordinary high-water mark moves due to short- or long-term events such as coastal erosion, sea level rise, or other phenomena.

  b) PG&E shall establish an Access Plan, subject to CCC approval. The plan shall, at minimum, include a legal description of the accessway as recorded on the property deed and a description of improvements that will be made to ensure public access is safely maintained. Measures that will be taken to maintain the accessway in a safe and usable condition to ensure safe pedestrian use shall include providing a level walking surface, regularly inspecting accessway conditions, placing trash receptacles on or near the trail and placing signs at both ends of the accessway that describe the access available and the conditions related to the adjacent ISFSI that may affect access. The design and placement of signs shall be consistent with those developed as part of the Humboldt Bay Trails Feasibility Study.

  c) Changes to Access: If any change to the safety or security measures associated with the ISFSI results in a change to, or limitation on, public access to the shoreline, PG&E shall file a complete application to amend this permit. The application for an amendment shall describe the nature of the change and its effect on public access and shall include proposed measures that would provide at least an equivalent amount of shoreline access on or near the ISFSI site.

Similar requirements are contained in the other CDPs issued for canal remediation and the FSR. HBPP Management will work with the CCC to standardize the language between the CDPs into the ISFSI CDP, so that PG&E may request termination of the non-ISFSI CDPs.

PG&E will be required to submit a new CDP or CDP amendment application to the CCC to address decommissioning of the ISFSI and restoration of the ISFSI site. ISFSI decommissioning will likely include removal of ISFSI roads, offices and support facilities. Whether there will be additional permit requirements is not known at this time.

E. Estimate by Cost Category

As authorized in prior NDCTPs, PG&E estimates and then tracks costs against specified cost categories; the specified categories are reflected in Table 8-2. With the closure of the Civil Works scope of work, many of these categories are now closed out, and presented for review in Chapter 9. FSR, Residual Remediation/Waste Disposal, Tools & Equipment – Common and Office Facilities Rent were moved from their corresponding blue line cost categories, so the associated cost categories could be closed out.

The following cost categories remain open for the completion of HBPP decommissioning:

<u>General Staffing</u> costs associated with the overhead staffing costs to support License Termination Survey and FSR/FSS oversight;

<u>Small Value Contract</u> costs associated with Small Dollar Vendors, Specialty Contracts, remaining FSR, tools and equipment, Residual Remediation/Waste Disposal and office facility rent; and

<u>Spent Fuel Management</u> costs for ISFSI staffing, Operations and Maintenance (O&M); ISFSI Engineering and Specialty Contracts; ISFSI infrastructure expenses; NRC fees; DOE transfer and ISFSI removal after DOE transfer.

TABLE 8-1
2018 NDCTP COST TO COMPLETE HBPP DECOMMISSIONING

	Estimate to Complete	Approved 2015 NDCTP Budget $2018	
Line No.	2018 Cost Category	ETC 2019 to 2030 $2018	ETC 2031-2033 $2018
1	General Staffing (Excludes Caisson)	13,170,667	–
2	Overall Project (CWC Oversite)	–	–
3	License Termination/FSS Oversite	9,374,233	–
4	License Termination Survey (Excludes Caisson)	3,796,433	–
5	Small Value Contracts	21,070,030	–
6	Small Dollar Vendors	348,487	–
7	Specialty Contracts	5,622,074	–
8	Final Site Restoration	12,131,414	–
9	Residual Remediation/Waste Disposal	1,087,709	–
10	Tools & Equipment-Common	883,350	–
11	Office Facilities Rent	996,996	–
12	Spent Fuel Management	123,207,562	25,067,582
13	Security (PG&E)	77,905,517	20,208,927
14	ISFSI O&M	7,089,686	1,823,405
15	ISFSI Staffing/Engineering/Specialty Contracts	6,775,459	1,675,381
16	ISFSI Infrastructure Expenses	8,985,741	356,997
17	NRC Fees	3,415,162	1,002,873
18	ISFSI Removal	15,368,552	–
19	Transfer to DOE	3,667,446	–
20	Total	157,448,259	25,067,582

Note: These costs include contingency of approximately 16 percent.

1. General Staffing

The cost of staffing (labor) is a significant portion of the remaining overall costs of the HBPP decommissioning. Both the cost of direct labor to perform the work and the cost of overhead labor to support the direct labor force contribute to the total labor costs. The ISFSI will continue in operation until the DOE takes custody of the SNF and GTCC waste, which is expected to commence in 2031. The ISFSI staffing costs are included in spent fuel management, and they are not included in the Overall Project staffing.

Through proactive planning, PG&E has done an excellent job of managing the total workforce. During the period 2012 through 2018, the General Staffing personnel focused efforts on self-performance and civil work scopes of work. After FSR is complete, the General Staffing focus will be on FSS and license termination support activities. The estimated remaining cost for General Staffing is $13.17 million.

a. Final Site Restoration/License Termination/FSS Oversight (Overall Project)

The staffing for FSR/License Termination/FSS Oversight continues through 2019 and ends in 2020. The Staffing Plan ramps down the latter part of 2020, with the final submittal of FSS documents to the NRC. During closeout of the project in 2020, the staffing plan is at a minimum headcount as PG&E submits the 10 CFR Part 50 License Termination Request, completes invoice processing, and transmits documents to the Records Management System (RMS).

The staffing for FSR/License Termination/FSS Oversight includes Fixed Overhead. These are the costs incurred for maintaining staff who are assigned to Management, Safety, Facility Maintenance, Licensing Support, Procurement and Finance roles and responsibilities. Fixed Overhead is job functions that are needed regardless of the status and progress of the decommissioning. It also includes direct and discrete labor, which are staffing costs for personnel who directly support schedule progress, such as engineered plans, development of work packages, permits and maintenance of the programs required by regulation, license or the company, in order to ensure that the FSS is accomplished safely and efficiently. Site Management Department

The FSR/License Termination/FSS Oversight staff is distributed within the following departments:

- Site Management (Director)
- Decommissioning
- Environmental
- Site Closure

1) Site Management

To ensure project success, PG&E recruited a highly-experienced and specialized group of managers with solid management skills, strong technical skills, industry-specific knowledge and the desire to see the project succeed through the critical phases. The low attrition rate, strong participation in professional and industry forums and proven ability to solve unexpected problems has validated the selections. The combination of PG&E and contractor personnel with specialized skill sets has proven to be very cost-effective. Industry evaluations, audits, NRC inspections, project safety achievements and project accomplishments attest to the team's ability to manage the project within the project parameters. This strategy was used throughout the decommissioning process and will continue through the completion of FSS. Refer to 2015 DPR, Section 3.3.1.1.2 for details on PG&E Management strategy for Site Management staffing.

The current management organization continues to be well-suited to manage and oversee the completion of the FSS and the ultimate termination of the 10 CFR Part 50 license. Based on the status to-date and the schedule going forward, HBPP Management plans to reduce direct reports as their specific specialties warrant. The RP Manager was released in 2017, with any residual responsibilities being managed by the Site Closure Manager. The Deputy Director was released in 2017, with any residual responsibilities being managed by the Environmental Manager. The Decommissioning Manager was released in 2017. Any of the Decommissioning Manager's residual responsibilities are being managed by the remaining site leaders, Site Closure, Environmental and Business Analysis.

The following are key staff positions in the Director's organization:

<u>HB Senior Director/Plant Manager-Nuclear</u>

The HB Senior Director/Plant Manager-Nuclear (Director) has the responsibility for oversight of the entire decommissioning and site restoration, including safety of employees, implementation of work processes, disposal of wastes and control of the budgets to accomplish the entire project. The Director works collaboratively with a wide variety of other groups to safely and efficiently execute the mission. These groups include a mix of internal stakeholders, such as Site Closure, Safety, Security and Quality Verification, as well as external stakeholders, such as interested state and federal regulators, other utilities preparing to decommission facilities and local community groups, such as the Community Advisory Board.

Decommissioning Business Analysis Supervisor

The duties and responsibilities of the Decommissioning Business Analysis Supervisor relate to the day-to-day activities of the Finance, Litigation and Project Controls groups; manages the Corrective Action Program; oversight of remaining self-perform work field activities; and oversight of the contractors and contracts for the FSS. This position is primarily responsible for the Cost and Schedule baselines and managing the line-of-business interests for PG&E previously performed by the Decommissioning Manager.

Site Closure Manager

The Site Closure Manager supervises the License Termination Survey staff, manages site training and regulatory affairs matters previously performed by the Decommissioning Manager. He also assumed Radiological Program management duties previously performed by the RP Manager.

Engineering Manager

The Engineering Manager is provided by Diablo Canyon Power Plant (DCPP) and is available to the Director to address any decommissioning matters involving engineering issues.

Environmental Manager

The Environmental Manager supervises the Environmental organization and responsibilities for decommissioning management performed previously by the Deputy Director and the Decommissioning Manager.

HBPP Trust Fund Consultant-Expert

The HBPP Trust Fund Consultant-Expert is the PG&E Subject Matter Expert (SME) for the Nuclear Decommissioning Trust Fund, performing reviews and submitting back-up documentation for trust fund expenditures. This position also provides data to comply with NRC funding assurance requirements.

DOE Litigation Specialist

The DOE Litigation Specialist is responsible for the preparation of PG&E claims against the DOE as part of the Settlement Agreement. Under the Settlement Agreement, annual DOE claims are prepared and submitted for reimbursement.

2) Decommissioning Department

The Decommissioning Department is responsible for performing cost and budget control, procurement and warehouse functions. Decommissioning is also tasked with oversight, identification and control of the execution of project transition and work. The Decommissioning Department structure is depicted in Attachment C.

The Decommissioning Department is the central group responsible for planning, executing and tracking progress and funding for the decommissioning of HBPP Unit 3. To effectively execute its assigned missions, the makeup of the Decommissioning Department has changed over time, with changes to the workload and to the remaining work to oversee. The downward trend is expected to continue through the completion of the decommissioning project closeout.

3) Environmental Department

The Environmental Department (depicted in Attachment D) is responsible for implementing the environmental and safety procedures and programs; and interfacing with agencies on permitting, as well as stakeholders who have concerns about areas of cultural, paleontological and biological significance at the site and surrounding areas.

The Environmental Department activities will continue through the FSS and project closeout of the Voluntary Cleanup Agreement between PG&E and the California Department of Toxic Substance Control, as well as the processing of any waste generated from FSS and termination of the decommissioning permits.

b. Site Closure Department (License Termination Survey [Excludes Caisson])

The Site Closure Department staff is responsible for license termination activities, such as O&M of the Count Room, maintaining and submitting updates to the HBPP LTP, performing and documenting the FSS, coordinating with NRC oversight, and generating reports to the NRC and State of California regulators.

To support FSS, Site Closure Department staff assigned as Radiation Protection (RP) Technicians implement the programmatic and procedural requirements established to satisfy 10 CFR Part 20, Unit 3 Technical Specifications, and 10 CFR Part 19. The RP Technicians also contribute to the implementation of Radiological Environmental Monitoring Program (REMP) and compliance with 40 CFR Part 190.

As the FSS-required data is collected and reduced and documents transmitted to the NRC, the staffing for the Site Closure Department will decrease accordingly.

2. Small Value Contracts

Small Value Contracts categories include:

- Small Dollar Vendors
- Specialty Contracts
- Final Site Restoration
- Tools and Equipment
- Residual Remediation/Waste Disposal
- Office Facility Rent

The remaining cost to complete for this category is estimated to be $21.1 million.

a. Small Dollar Vendors

Small Dollar Vendors are associated with contracts for providing HBPP site maintenance and FSS support field labor, as well as supporting SWWPP mitigation. Small Dollar Vendors also includes the collection of recurring costs that are expected to continue through the completion of FSS. These include:

- Circuit Leasing and Internet Services

- Computer Software and Hardware
- Employee Training, Travel and Meal Expense
- Electric Power Research Institute Membership
- Mitigation and Monitoring Implementation
- Office Supplies
- Printer Rental and Maintenance Support
- Shuttle Services
- Water and Sewer Services
- Decommissioning Plant Coalition Representation
- Landscape and Site Maintenance
- Printing and Document Shredding Services
- Department of Public Health Fees
- State Water Resource Control Fees

b. Specialty Contracts

Specialty Contracts are issued for specific skills or services not performed by HBPP staff. They include various elements, such as permitting fees, environmental contracts, NRC fees and other miscellaneous specialty consultations.

Services covered in this category include NDCTP SME, Oak Ridge Associated Universities SME, FSS support services, relocation services, biological monitoring and reporting services, chemical analysis sampling services, hazardous waste disposal, Care Onsite Services, legal representation and support, Oracle P6 system software and services, other support and training, NRC interface, permitting and permitting assistance and other necessary services to support the FSS and license termination on an ongoing basis.

c. Final Site Restoration

FSR includes remaining demolition, removal of remaining equipment, excavation, grading, drainage, wetland construction, ground cover (vegetation and other surfacing), installation of fencing, installation and construction of new components and repairs to existing features of the HBPP site (including roadways) to configure the site for future industrial use.

FSR costs were initially included In the Civil Works Scope. Other than completion of FSR, the Civil Works Scope has been completed. To enable PG&E to close out Civil Works, PG&E has moved FSR costs to the Small Value Contracts category. This work scope is being performed by the CWC and is scheduled to be completed in 2019. The remaining costs for FSR are $12.1 million.

d. Tools and Equipment

The tools and equipment required to support completion of FSS are associated with RP Tools and Equipment. Typical tools and equipment purchased to support RP and FSS work include consumables (polyethylene sheeting, sample containers, general office supplies and items to assist in contamination control); Personal Protective Equipment (PPE); contamination detection instrumentation; fire extinguishers; eyewash stations; first aid kits; blood-borne pathogen kits; and other specially-customized materials. Also included is replacement of radiation monitoring instruments and detectors.

e. Residual Remediation/Waste Disposal

During FSS, there is a possibility that licensed material that is greater than the values established in the HBPP LTP, or hazardous materials not previously identified, will be discovered. This material will need to be removed and isolated for ultimate disposal.

Waste Disposal also includes the costs associated with the disposal of non-releasable tools and equipment or radioactive and hazardous materials from FSS. Waste generation from FSS is expected to be minimal and to fall into one of the following categories:

- Noncompliant Waste
- Low-Level Radioactive Waste

f. Office Facility Rent

To facilitate Caisson removal, PG&E arranged with the College of the Redwoods to lease vacant office space on the campus. PG&E was able to relocate support staff from the decommissioning site to the College of the Redwoods as the staff was systematically displaced onsite. Upon completion of FSR, the only personnel who will physically remain at the HBPP decommissioning site are the Site Closure Department staff assigned to the Count Room and the ISFSI staff. All other FSS support staff are located at the College of the Redwoods.

The costs associated with use of the College of the Redwoods property as office space was included in the 2015 in the DCPP in the category titled Common Site Support - Caissons and Canals. Since this scope of work has been completed, for the 2018 NDCTP filing, the ongoing costs associated with the College of the Redwoods space rent is included under Small Value Contracts.

3. Spent Fuel Management

The O&M of an ISFSI includes a multitude of activities to ensure the SNF and GTCC waste is stored in a manner to protect public health and safety. The 2015 DPR, Section 3.3.1.8 provides a detailed discussion related to the cost basis for Spent Fuel Management.

Since PG&E assumes a delay in transfer of SNF and GTCC waste by the DOE From 2028 to 2031, the current estimate includes an additional $25.1 million in forecast spent fuel management costs. These costs are comprised primarily of:

- Security staffing
- O&M
- ISFSI Specialist/Engineering/Specialty Contracts
- Infrastructure improvements
- ISFSI FSR
- NRC fees

a. Security (PG&E) Staff Costs

The HB ISFSI staffing includes a Security element to provide 24-hour surveillance of the SNF to comply with NRC security regulations and the HB Emergency Plan and ISFSI Physical Security Plan.

b. ISFSI Operating and Maintenance Costs

ISFSI O&M functions include effective and efficient ongoing management, safety and compliance necessary to meet NRC requirements.

Overhead costs to maintain the HB ISFSI include: PPE; physical, auditory, and psychological testing for Fitness-for-Duty requirements; uniform supplies; arms and ammunition; radio and cellular equipment and service; specialty training; office supplies; and facility services and maintenance.

c. ISFSI Staffing/Engineering Services/Specialty Contracts

HB ISFSI non-Security related support is provided by a number of sources, including DCPP organizations, ISFSI specialists and vendors.

The DCPP organizations provide support in areas of Engineering, Human Resources, Procurement, Quality Verification, Records Management, and Regulatory Affairs.

The ISFSI Specialists within the ISFSI organization perform Administrative services, Emergency Planning, Training and are the liaisons with the DCPP support organizations.

Vendors provide infrastructure support as engineering services (through DCPP organizations) and specialty contracts for scope of work activities not provided by DCPP staff or HB ISFSI specialists.

d. ISFSI Infrastructure Expenses

ISFSI Infrastructure Expenses includes those costs associated with maintaining compliance with the regulatory requirements associated with the storage of SNF and GTCC wastes at the ISFSI and the ultimate removal of the HB ISFSI. Ongoing projects identified in the 2015 HBPP DPR include:

<u>Building 6 Conversion to Onsite ISFSI Weapons Training Facility</u>

The Building 6 Conversion to On-Site ISFSI Weapons Training Facility has not yet been implemented due to the unavailability of Building 6 for the conversion. The building to be converted was occupied by personnel involved with the decommissioning. The conversion is scheduled to be completed in 2019.

<u>Care Onsite</u>

The establishment of a Care Onsite for the ISFSI has not yet been implemented due to the unavailability of Building 6. The establishment of the Care Onsite facility will be completed after the Count Room

(Building 13) is converted to offices for the HB ISFSI staff (scheduled in 2020).

Building 13 Retrofit Upgrade for ISFSI

The retrofit of Building 13 (Count Room) to support the ISFSI as offices has not yet been implemented due to the unavailability of the building. The Count Room was occupied by personnel involved with the FSS. Building 13 retrofit is scheduled to be converted to offices for the HB ISFSI staff after the completion of FSS in 2020.

InfoQual Program Migration to MyLearning

The migration to the InfoQual Program training database is in progress and is expected to be completed in 2019.

e. NRC Fees

10 CFR Part 171 "Annual Fees for Reactor Licenses and Fuel Cycle Licenses and Material Licenses, including Holders of Certificates of Compliance, Registrations, and Quality Assurance Program Approvals and Government Agencies Licensed by the NRC" establishes the authority for the collection of annual fees from those who possess a license issued under 10 CFR Part 40, 10 CFR Part 50, 10 CFR Part 52, 10 CFR Part 70, or 10 CFR Part 72. Additionally, there are costs associated with periodic NRC inspections conducted by the NRC Region IV.

HBPP license fees are split between Decommissioning, FSS and the HB ISFSI through the termination of the 10 CFR Part 50 license. With the termination of the 10 CFR Part 50 license, the license fees associated with the HB ISFSI will be solely associated with the 10 CFR Part 72 license, until the 10 CFR Part 72 license termination after the SNF and GTCC waste are removed from the ISFSI and the completion of the ISFSI FSS.

f. ISFSI Removal

Approximately two years before DOE is scheduled to remove the SNF and GTCC waste, PG&E will prepare and submit an ISFSI LTP for NRC approval. After the last SNF/GTCC waste cask is accepted by the DOE carrier, PG&E can request an exemption from the NRC of the

10 CFR Part 72 requirements and commence the decommissioning of the HB ISFSI site.

The decommissioning and ISFSI site restoration will include demolition of the buildings and the ISFSI Vault, FSR of the ISFSI site and the building areas, and implementing the ISFSI LTP with FSS of the ISFSI site and building areas. After the ISFSI FSS documentation is reviewed and accepted by the NRC, PG&E will request termination of the 10 CFR Part 72 license.

g. Transfer to DOE

PG&E assumes the DOE will begin taking the SNF and GTCC waste packages in 2031. Once the DOE provides its schedule for accepting the SNF and GTCC waste packages, PG&E will begin the planning processes necessary to facilitate the transfer to the DOE. There are five SNF casks and one GTCC waste cask to be transported and removal is expected to take a little over a year (one cask in 2031 and five casks in 2032).

The planning phase for SNF and GTCC waste transfer is expected to take six months to a year of effort prior to the transport to the DOE. The 2015 DPR, Section 3.3.1.8.6 provides details related to planning and facilitating the transfer of the SNF and GTCC waste to DOE custody.

Once the DOE carrier has accepted the SNF or GTCC waste shipment, it becomes the property of the DOE and PG&E's responsibilities for the SNF or GTCC waste is terminated.

F. Planned Schedule and Activities

Almost all of the decommissioning physical work was complete in 2018, with FSR scheduled to complete in 2019. Despite innumerable challenges and risks, PG&E has successfully maintained its decommissioning schedule.

In 2019, HBPP's Site Closure Department will complete FSS and will be generating the last area reports and summary report to be submitted to the NRC. In 2020, the LAR to terminate the license will be sent to the NRC and the transmittal of FSS records will be processed to the RMS.

In addition to FSS and FSS records closure, HBPP Site Closure will perform administrative closeout during this 24-month period. Like many other aspects of HBPP decommissioning, the administrative closeout will also be yet another first-of-its-kind experience for both HBPP Management and the state of California. PG&E will transfer control and stewardship of the HBPP site area to the non-nuclear Humboldt Bay Generating Station (HBGS). As such, the administrative closeout is anticipated to bring its own set of challenges for PG&E.

HBPP Management will need to perform a number of activities. It is important to note that closure of the following activities and the retention of the records thereof, must each adhere to its own unique and separate standards set forth by federal regulations, California regulations, local regulations, nuclear industry standards, PG&E's nuclear insurer, PG&E standards, PG&E's commitments to the community and to the community's expectations. To meet the administrative closeout needs, HBPP Management is planning to retain a mixture of management- and clerical-level personnel who have experience with the HBPP decommissioning and can accomplish the residual work. Anticipated work during the two-year administrative period includes:

<u>Work Package Closeout</u> – Work packages will be verified to be complete and accurate. The records will then be entered in the RMS for retention and archiving, in accordance with the applicable regulations and requirements.

<u>Radiological Records</u> – All radiological records, such as surveys, radiation work permits and dosimetry records must be verified complete and transmitted to the RMS.

<u>Industrial Hygiene and Environmental Sampling</u> – All Industrial Hygiene and Environmental Sampling and records will be verified complete and accurate, then transferred to the RMS.

<u>SNF and GTCC Waste Records</u> – PG&E shall verify that all the records for SNF, GTCC waste and associated packaging are complete per DOE standards and retrievable. This is a long-term preparation for PG&E, as DOE standards require specific documentation prior to acceptance of the SNF or GTCC waste package.

Corrective Action Program – Incomplete SAP Notifications and outstanding Corrective Actions from the project will be brought to closure or if required, transferred to ISFSI or other intra-company organizations.

Procedure Termination or Transfer – HBPP procedures will be processed for termination or transferred to HBGS.

Disposition of Permits – The disposition of the various agency permits includes taking no action for permits that were never used, allowing permits with sunset dates to expire and working with respective agencies to combine requirements and apply those requirements to permits that will continue past FSS.

Asset Recovery – HBPP Management will have to determine the processes to evaluate the remaining tools, equipment, office equipment, office furniture and supplies. The remaining assets will be sold, salvaged, scrapped or disposed.

Final As-Built Drawings – The CWC will prepare the final drawings and applicable topography records, indicating the status of the site with the best available information at the end of the project. The final drawings include depictions of above-ground and below-grade piping, utilities, residual structures, active monitoring systems and abandoned systems.

License Termination Support – HBPP Management will prepare for license termination inspections and respond to Requests for Additional Information, as required.

Preparation for NDCTP – HBPP Management will begin preparation for the 2021 NDCTP filing.

Residual Workload from All Applicable Stakeholders – There are a number of unknowns associated with stakeholder expectations. HBPP Management has made the utmost effort to maintain transparency about the status of project execution and to keep open lines of communications with local regulatory bodies and stakeholders. The amount and level of communication is expected to diminish after site restoration is complete. However, local stakeholders will continue to have an interest in the site for as long as SNF and GTCC waste is in temporary storage at the ISFSI.

From 2021 onward, HBPP Site Management will be focused on ISFSI Management. During this period, the ISFSI site will be managed by the DCPP Nuclear Security and Emergency Services Department, until DOE removes the

SNF and GTCC waste. The removal of the SNF and the GTCC waste casks is planned to commence in 2031, followed by the ISFSI decommissioning, ISFSI FSS and license termination scheduled for 2033.

G. Decision Log

Commission Decision D.14-02-024 specified that PG&E maintain an ongoing Decision Log to track its decision-making activities relative to HBPP nuclear decommissioning activities. Items requiring documentation in that log include decisions having the potential to affect any cost category by more than 10 percent, either positively or negatively. There have been no such decisions made since the 2015 DPR.

H. Trust Disbursement Advice Letters

PG&E will continue to file annual Trust Disbursement advice letters for HBPP which includes the information required by prior NDCTP decisions. PG&E's most recent advice letter, Advice Letter 5239-E, was approved by the Energy Division effective March 30, 2018.

I. SAFSTOR

SAFSTOR was the initial form of decommissioning selected by PG&E for HBPP. The NRC regulatory requirements for SAFSTOR include routine and specific radiological surveys, training and qualification of RP personnel performing surveys, routine reporting to the NRC, maintenance of the Radiological Effluent and REMP, and implementation of a radiation safety program to comply with 10 CFR Part 20 regulations and applicable NRC guidance documents. PG&E has recovered SAFSTOR expenses through a separate revenue requirement updated in each NDCTP.

When PG&E decided to commence the active decontamination and dismantlement phase of decommissioning, the SAFSTOR regulatory requirements continued to be maintained by the RP Department. In the 2015 NDCTP filing, annual revenue requirements for SAFSTOR were adopted for 2017-2019; the Commission approved revenue requirement for SAFSTOR for 2019 is $4.4 million (nominal $). Termination of the 10 CFR Part 50 license will terminate the need to maintain SAFSTOR regulatory requirements, and PG&E proposes to cease collecting funds for SAFSTOR in 2020. Since the 2019 annual revenue requirement has already been adopted, this DCE includes no SAFSTOR estimate.

J. Conclusion

PG&E requests that the Commission adopt the decommissioning cost estimate for HBPP as set forth in this chapter.

TABLE 8-2
HBPP DECOMMISSIONING COST BREAKDOWN

	2012 NDCTP Budget[1]	2015 NDCTP Budget[1]		2018 NDCTP Completed Activities/Forecast to Go			Presented for Reasonableness Review			Forecast
2018 NDCTP Table	A Approved 2012 NDCTP Nominal / $2014	B Approved 2015 NDCTP Nominal / $2014	C Approved 2015 NDCTP Nominal / $2018	D 2012-2018 Project Spend	E ETC 2019 To 2030 $2018	F Total EAC 2012 To 2030 Nominal / $2018	G Previously Submitted for Reasonableness Review 2012-2016	H Presented for Reasonableness Review 2018 NDCTP	I Remaining for Reasonableness Review F-(G+H)	J 2031-2033 Estimate $2018
General Staffing (Excludes Caisson)	**102,442,205**	**118,212,981**	**121,088,868**	**107,918,201**	**13,170,667**	**121,088,868**	**66,432,824**	**28,138,098**	**26,517,946**	
Overall Project (CWC Oversight)	89,746,964	95,161,092	96,267,287	94,570,922		94,570,922	66,432,824	28,138,098		
License Termination/FSS Oversight		6,543,250	7,677,868		9,374,233	9,374,233			9,374,233	
License Termination Survey (Excludes Caisson)	12,695,241	16,508,639	17,143,713	13,347,279	3,796,433	17,143,713			17,143,713	
***Remainder of Plant Systems / PG&E Civil Works Support**	**59,998,149**	**48,431,565**	**48,581,707**	**48,376,707**		**48,376,707**	**43,748,081**	**4,628,626**		
Direct Labor (PG&E and Contractor)	34,634,453	35,007,658	35,124,945	34,919,944		34,919,944	32,223,080	2,696,864		
Liquid Radwaste System	7,127,430	4,282,774	4,282,774	4,282,774		4,282,774	4,282,774			
Tools & Equipment	18,236,266	10,372,554	10,457,339	9,573,989	883,350	10,457,339	7,642,227	1,931,762	883,350	
FSS Tools & Equipment		(831,420)	(883,350)		(883,350)	(883,350)			(883,350)	
Disallowed Scope (Seismic Upgrades)		(400,000)	(400,000)	(400,000)		(400,000)	(400,000)	-		
***Site Infrastructure**	**3,246,534**	**4,935,540**	**4,935,540**	**4,935,540**		**4,935,540**	**4,935,540**			
***Specific Project Costs**	**98,596,847**	**103,780,637**	**106,841,555**	**107,578,702**	-	**107,578,702**	**29,002,996**	**78,575,706**		
Reactor Vessel Removal[2]	15,896,279	16,956,917	17,003,018	16,983,379		16,983,379	16,984,115	(736)		
Turbine Bldg. Demolition (Contractor)	14,370,353	12,118,881	12,118,881	12,118,881		12,118,881	12,118,881			
Civil Works Contract	80,152,232	75,024,060	78,048,337	78,669,240		78,669,240		78,669,240		
Facilities Demolition	66,718,122	69,817,635	72,478,394	75,950,216		75,950,216		75,950,216		
Office Trailer Demobilization	1,612,093	1,992,479	2,168,191	2,227,645		2,227,645		2,227,645		
Final Site Restoration	11,822,016	37,253,566	40,412,905	28,281,491	12,131,414	40,412,905			40,412,905	
Final Site Restoration	(11,822,016)	(37,253,566)	(40,412,905)	(28,281,491)	(12,131,414)	(40,412,905)			(40,412,905)	
Other Services/ Letter of Credit		3,213,946	3,401,752	491,379		491,379		491,379		
Disallowed Scope (Seismic Upgrades)		(319,222)	(328,681)	(192,798)		(192,798)	(100,000)	(92,798)		
***Waste Disposal**	**76,347,441**	**86,825,016**	**90,801,787**	**90,765,193**	-	**90,765,193**	**50,041,157**	**40,724,036**	-	
Labor (Packaging and Handling)	19,679,147	13,095,421	13,188,720	13,114,586		13,114,586	13,114,586			
Third Party Disposal Sites	53,920,640	69,991,255	73,874,727	73,912,267		73,912,267	33,188,231	40,724,036		
Waste Handling Building (Contractor)	2,747,654	3,765,430	3,765,430	3,765,430		3,765,430	3,765,430			
Disallowed Scope (Seismic Upgrades)		(27,090)	(27,090)	(27,090)		(27,090)	(27,090)			
Small Value Contracts	**47,690,392**	**77,575,353**	**81,979,921**	**60,909,891**	**21,070,030**	**81,979,920**	**21,575,949**	**11,052,452**	**49,351,520**	
Small Dollar Vendors	10,885,349	4,669,502	4,787,410	4,438,923	348,487	4,787,410	2,680,883	1,758,040	348,487	
Specialty Contracts	24,983,026	33,010,318	33,811,551	28,189,477	5,622,074	33,811,551	18,895,065	9,294,412	5,622,074	
Final Site Restoration	11,822,016	37,253,566	40,412,905	28,281,491	12,131,414	40,412,905			40,412,905	
Residual Remediation/Waste Disposal		904,973	1,087,709		1,087,709	1,087,709			1,087,709	
Tools & Equipment		831,420	883,350		883,350	883,350			883,350	
Office Facilities Rent		905,573	996,996		996,996	996,996			996,996	
Spent Fuel Management	**71,293,127**	**151,425,840**	**165,201,692**	**41,994,130**	**123,207,562**	**165,201,692**	**14,279,397**	**27,714,733**	**123,207,562**	**25,067,582**
Security (PG&E)	51,546,006	101,820,420	111,078,664	33,173,147	77,905,517	111,078,664	11,235,555	21,937,592	77,905,517	20,208,927
ISFSI O&M	8,505,931	9,863,067	10,634,509	3,544,823	7,089,686	10,634,509	1,632,172	1,912,651	7,089,686	1,823,405
ISFSI Staffing / Engineering / Specialty Contracts	3,224,018	9,103,600	9,742,463	2,967,003	6,775,459	9,742,463	1,089,192	1,877,811	6,775,459	1,675,381
ISFSI Infrastructure Expenses		10,096,960	10,875,464	1,889,723	8,985,741	10,875,464	77,231	1,812,492	8,985,741	356,997
NRC Fees	3,166,980	3,496,805	3,834,595	419,433	3,415,162	3,834,595	245,246	174,187	3,415,162	1,002,873
ISFSI Removal	2,155,641	13,712,201	15,368,552		15,368,552	15,368,552			15,368,552	
Transfer to DOE	2,694,551	3,332,787	3,667,446		3,667,446	3,667,446			3,667,446	
Subtotal Base	**459,614,695**	**591,186,932**	**619,431,070**	**462,478,363**	**157,448,259**	**619,926,622**	**230,015,943**	**190,833,650**	**199,077,028**	**25,067,582**
***Caisson**	**202,326,010**	**141,871,637**	**151,125,624**	**151,010,115**	-	**151,010,115**		**151,010,115**	-	
Field Work (Civil Works Contract)	120,595,389	86,383,087	90,599,420	89,807,911		89,807,911		89,807,911		
Project Staffing	31,463,244	17,643,186	18,869,164	13,231,648		13,231,648		13,231,648		
Waste Disposal	33,966,818	23,313,034	26,205,862	35,092,897		35,092,897		35,092,897		
License Termination Survey	6,548,881	4,189,348	4,486,368	5,398,254		5,398,254		5,398,254		
Tools and Supplies	2,465,351	1,253,037	1,301,563	763,662		763,662		763,662		
Other	7,286,327	9,089,943	9,663,248	6,715,743		6,715,743		6,715,743		
RP Discrete	480,514	1,338,207	1,425,435	1,498,091		1,498,091		1,498,091		
Small Dollar Vendors	6,429,029	864,504	925,740	227,505		227,505		227,505		
Specialty Contracts	376,784	6,887,232	7,312,073	4,990,147		4,990,147		4,990,147		
***Canal Remediation**	**51,284,882**	**51,716,975**	**54,243,720**	**47,049,798**	-	**47,049,798**		**47,049,798**		
Removal (Civil Works Contract)	25,649,352	40,061,223	41,374,375	40,474,305		40,474,305		40,474,305		
Disposal	25,635,529	12,560,726	13,957,053	6,575,493		6,575,493		6,575,493		
Residual Remediation/Waste Disposal		(904,973)	(1,087,709)	-				-		
***Common Site Support - Caisson and Canals**	**6,021,784**	**4,804,455**	**4,865,608**	**4,821,953**		**4,821,953**	**2,391,776**	**2,430,176**		
Relocation of Trailer City	2,208,379	2,720,298	2,863,899	1,816,903	996,996	2,813,899		1,816,903	996,996	
Office Facilities Rent		(905,573)	(996,996)		(996,996)	(996,996)			(996,996)	
Groundwater Treatment	3,020,620	2,684,104	2,692,355	2,698,699		2,698,699	2,391,776	306,923		
Groundwater Treatment System Operation	792,786	305,626	306,350	306,350		306,350		306,350		
***EPC Services (including Quality Training)**	**3,924,982**	**10,469,693**	**10,980,931**	**8,850,788**		**8,850,788**		**8,850,788**		
EPC Services	3,924,982	9,651,929	10,117,403	7,538,356		7,538,356		7,538,356		
Other Services (Training)		817,764	863,528	1,312,432		1,312,432		1,312,432		
Subtotal Caisson / Canal / GWTS	**263,557,658**	**208,862,760**	**221,215,882**	**211,732,653**		**211,732,653**	**2,391,776**	**209,340,877**		
TOTAL 2015-2030	723,172,353	800,049,692	840,646,952	674,211,017	157,448,259	831,659,275	232,407,720	400,174,527	199,077,028	
Spent through 2011 (Prior to 2012 NDCTP Filing)	254,750,101	254,750,101	254,750,101	254,750,101		254,750,101	254,443,589	3,149	303,363	
Total Including spend prior to 2012 NDCTP	977,922,454	1,054,799,793	1,095,397,053	928,961,118	157,448,259	1,086,409,376	486,851,309	400,177,677	199,380,391	25,067,582
		2031-2033 Estimate				25,067,582				
		Total Spend/Forecast				1,111,476,958				
		*Closed Out Cost Category Savings				(8,987,677)				
Notes: *Closed out Blue Lines 1. Budget Includes Contingency 2. Reactor Vessel Removal has a credit of $736 in column H due to a late invoice credit		Additional Funding Requested for 2031-2033 (Total Spend/Forecast-Approved Budget)				16,079,905				

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

HUMBOLDT BAY POWER PLANT COMPLETED PROJECT

REASONABLENESS REVIEW TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
HUMBOLDT BAY POWER PLANT COMPLETED PROJECT REASONABLENESS REVIEW TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
HUMBOLDT BAY POWER PLANT COMPLETED PROJECT REASONABLENESS REVIEW TESTIMONY

A. Introduction

The purpose of this chapter is to demonstrate the reasonableness and prudence of decommissioning scopes of work at Humboldt Bay Power Plant Unit 3 (HBPP) that have been completed since the 2015 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) application was filed in March 2015. This chapter also discusses Pacific Gas and Electric Company's (PG&E) efforts to retain and utilize qualified and experienced personnel to perform physical decommissioning, and accounts for the differences between forecast and actual Safe Storage (SAFSTOR) expenses for 2016 through 2018.

B. Summary

By the end of 2018, PG&E expects it will successfully have completed the Civil Works Phase (CWP),[1] a major phase of HBPP decommissioning. Decommissioning HBPP has presented a number of challenges due to the unique design and construction of the plant; radiological activation and contamination left from the early operation of the facility; and difficult site conditions. PG&E is very proud to have completed this work safely, on schedule, within approved cost estimates and without radiological incident. The HBPP Completed Projects Review included as Chapter 9, Attachment A and the HBPP Decommissioning Pictorial Summary included as Chapter 9, Attachment B attest to the complexity of the job and demonstrate PG&E's achievement in successfully completing the majority of the CWP.

PG&E has built an industrywide reputation for HBPP decommissioning, playing a leading role in industrial and occupational safety, and for radiation innovations that may be applied throughout the industry. HBPP was awarded the annual Shermer L. Sibley Award six times, the most prestigious PG&E award an organization can earn in recognition of its safety achievements. The

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[1] Final Site Restoration (FSR) work, which is being performed by the Civil Works Contractor (CWC), is scheduled to be completed in mid-2019.

CWP of decommissioning has a project safety record of no Occupational Safety and Health Administration (OSHA) lost-time injuries for more than five years and almost no recordable injuries (two in five plus years), even though it involved significantly challenging excavation and demolition work, much of which involved First of a Kind (FOAK) evolutions.

PG&E has also been recognized by Nuclear Regulatory Commission (NRC) Commissioners who have made on-site visits, and NRC regulators have routinely advised national and international nuclear industry companies to use HBPP as the standard on accomplishing decommissioning safely and with lowest radiological dose to workers. In 2015, the CWC received a Facility and Plant Services Safety Excellence Award. The HBPP site was featured in Engineering News Record (ENR) in a May 2016 article for novel tactics to demolish the nuclear caisson. In 2018, the HBPP team was recognized by ENR as California Project of the year for best specialty project. PG&E's CWC was recognized by the National Safety Council and received the Green Cross for Safety medal. This award is presented to organizations that have distinguished themselves through outstanding safety leadership with a commitment to safety by building successful partnerships to save lives and prevent injuries.

PG&E is presenting for review in this chapter $400.2 million in costs for completed work that occurred between 2012 and 2018. 2018 costs include actual costs incurred through August 31, 2018 and forecasted costs from September 1, 2018 through December 31, 2018. If necessary, PG&E will provide a true-up for actual costs from September 1, 2018 through December 31, 2018.

Each of the following scopes of work presented for reasonableness review were completed within 1.0 percent, or below, the approved cost estimate:

- $28.2 million in General Staffing, which includes all General Staffing for the CWP including CWC oversight, except staffing associated with License Termination and FSR, which is ongoing, and General Staffing associated with the Caisson Removal, which is included within that scope of work;
- $4.6 million in Remainder of Plant Systems, which includes Tools and Equipment, Direct Labor and Radiation Protection (RP) staff associated with the CWP;

- $78.6 million in Specific Project Costs, which includes all work for Nuclear Facilities Demolition and Offices and Facilities Demolition;
- $40.7 million in Waste Disposal Costs, which includes waste disposal associated with the CWP, excluding $35.1 million for Caisson Removal and $6.6 million for Intake and Discharge Canal Remediation scopes of work, for which Waste Disposal Costs are included in their respective scopes of work;
- $11.1 million in Small Value Contracts, which includes all Small Dollar Vendors and Specialty Contracts incurred through December 31, 2018 except those associated with Caisson Removal;
- $27.7 million in Spent Fuel Management which includes Independent Spent Fuel Storage Installation (ISFSI) security staffing, ISFSI Operations and Maintenance (O&M), ISFSI Infrastructure, Engineering, Specialty Contract and NRC fees incurred from 2016 through 2018;
- $151.0 million for Caisson Removal, Slurry Wall/Cutter-Soil Mix (CSM) Wall, Dewatering, Caisson License Termination Survey staff, Caisson Specialty Contracts, Caisson Small Dollar Vendors, Caisson Tools and Equipment, RP discrete labor (including $35.1 million in Waste Disposal and $13.2 million in Project Staffing costs);
- $47.0 million in Intake and Discharge Canal Remediation for removal of the Intake and Discharge Canals (including $6.6 million in Waste Disposal costs);
- $2.4 million in Common Site Support, which includes the Groundwater Treatment System (GWTS); and
- $8.9 million in Engineering, Procurement and Construction (EPC) scope.

C. Background

Under the procedures affirmed by the California Public Utilities Commission (CPUC or Commission) in Decision (D.)10-07-047, PG&E submits periodic advice letters requesting authorization to withdraw funds from the qualified and non-qualified Nuclear Decommissioning Trusts (NDT) to fund HBPP decommissioning work. Once specific projects are completed, PG&E enumerates them in NDCTPs for the Commission to review and determine whether the actual costs were reasonable and prudently incurred.

In D.10-07-047, the Commission defined how it would evaluate the reasonableness of the utilities' decommissioning activities: "[W]e define reasonableness for decommissioning expenditures consistent with prior Commission findings; *i.e.*, that the reasonableness of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made."[2]

PG&E's most recent decommissioning cost estimate for HBPP was approved in the 2015 NDCTP.

D. Specific Challenges

The HBPP nuclear decommissioning project has had unique challenges due to its specific design features: highly congested site, significantly contaminated underground systems and utilities, limited site access, a high-water table and frequent adverse weather conditions. Further, multiple discrete work activities occurring simultaneously throughout the course of the decommissioning require close coordination, communication and interface among on-site entities. Known challenges that have driven the cost to perform decommissioning work at HBPP include the following:

<u>Innovative Construction of Facility</u>

PG&E completed construction of HBPP in 1963; HBPP was one of the oldest commercial nuclear power plants in the United States (U.S.). PG&E adopted many unique features in the design and construction of HBPP, including the construction of a pressure suppression system. Instead of an above-ground containment dome, HBPP was built as an airtight, underground chamber constructed out of steel and concrete (Caisson). The cavity was partially filled with water to suppress the condensation of the steam that could be freed from the reactor system in case of an accident.

The construction technique used for HBPP was also unique and innovative. PG&E built the tank designated as the pressure suppression chamber on the surface of the ground. The bottom was equipped with "cookie cutter" edges, and water jets were placed underneath the tank. The water jets softened the soil and the cookie cutter edges then cut through the soil, causing the tank to sink into the ground under its own weight. The construction of the Caisson ultimately placed the lowest floor at approximately 66 feet below sea level, the bottom of

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[2] D.10-07-047*, mimeo*, p. 45 (footnote omitted).

the structure about 80 feet below grade and most of the structure below the water table.

Alpha Contamination

Operation of the plant in the early 1960s resulted in transuranic contamination, a unique radiological issue at HBPP, which has been a significant hazard at the site. Alpha contamination, when received as an internal dose, results in a dose about 1,000 times higher than beta or gamma contamination for the same activity. Safety is the number one priority in all aspects of the HBPP decommissioning, and mitigating this hazard requires work to proceed methodically to protect workers and the public.

Controlling the work environment to verify radiation protection (RP) compliance was very manpower intensive, but was important because a small nonconformance could have resulted in an overexposure. Because of the high levels of alpha contamination, extreme measures, such as decontaminating, sealing, or fixing equipment and piping prior to removal, were used to minimize the possibility of loose contamination becoming airborne. In addition, engineering controls such as respiratory protection, and increased oversight and monitoring of work activities and areas were needed. These important efforts had an impact on schedule and costs.

Regulatory Permit Integration

HBPP decommissioning is a high-profile, high-risk project that has high visibility with several local, regional, state and federal regulatory agencies. PG&E is decommissioning an old, contaminated nuclear power plant located on the bay within sight of the ocean, surrounded by environmentally sensitive wetlands with protected native wildlife species, in Northern California, amongst ranches, farms, fishing communities, redwood forests and a moderately large population center.

In addition to the NRC, there are several environmentally driven public agencies whose approval is required to conduct decommissioning and remediation work at HBPP. The agencies include: the U.S. Army Corps of Engineers, National Marine Fisheries Service, U.S. Fish and Wildlife Service, California Coastal Commission (CCC), California Department of Toxic Substances Control (DTSC), California Department of Fish and Wildlife (CDFW), North Coast Regional Water Quality Control Board (NCRWQCB), North Coast

Unified Air Quality Management District, and Humboldt County Building Department. Approval to work is by formal permit, participation agreement, and local, state, and federal law. Each major definable feature of work may have activity-specific supplements and addendums for conduct of work.

For a given work activity, the stipulations in one permit may conflict with the stipulations in another. HBPP environmental coordinators have different areas of expertise and often must confer and concur to determine an acceptable approach to compliance with all appropriate requirements. Notifications to agencies may be required for some activities. These coordination efforts can cause delays in the field.

Adherence to and compliance with local and state permit requirements have affected HBPP work activities to an extent that would have been difficult to predict or anticipate by work planners, engineers and construction specialists.

<u>Weather</u>

The HBPP Stormwater Pollution Prevention Plan (SWPPP) identifies all potential sources of pollution that may reasonably be expected to affect the quality of storm water discharges from the construction site. The SWPPP is a complex document that specifies actions, restrictions, limits and other controls to ensure site pollutants are not carried by water runoff into the surrounding area. Depending on the season and the daily work activities, SWPP compliance can be a labor- and time-intensive requirement that is disruptive to ongoing decommissioning work.

Eureka receives about 75 percent of its average annual rainfall during the rainy season, generally October through April, with greatest monthly totals in December and January. The area available for staging empty and filled waste containers and PG&E's ability to ship waste containers during the rainy season affected the rate at which the structures can be demolished.

<u>Process Water</u>

Process water is loosely defined as any legacy operations residual process-piping water, including water propelled through pumps for dust control, fixed and mobile equipment rinse water, cutting tool coolant and lubricant water, building floor and roof drain water, and radiation shield/contamination control water.

Process water is collected in tanks, then sampled and analyzed for chemical constituents. Previously, this water was discharged to the sewer district if it met volumetric inflow restrictions set by the county. In 2017, additional restrictions were applied to the discharges, and HBPP now uses alternate means for disposal.

Large, tracked construction equipment operating in excavations within the Radiological Control Area (RCA) had to be thoroughly cleaned and surveyed before release from the RCA. Pressure washers were occasionally used to assist the cleaning process, and water generated by this process action must be captured and transferred to collection tanks for sampling. This required constructing temporary collection basins, driving the heavy equipment into them and carefully controlling the runoff to prevent potential cross-contamination of the unprotected surrounding ground surface. Pumps and hoses had to be routed to transfer the water to designated storage tanks. The time and labor to perform these tasks was often greater than the time and labor required to excavate the ground.

Site Coordination and Congestion

The site footprint is extremely small and constrained and coordination among all parties performing work on site is critical. Very little space was available on site for laydown areas, soil stockpiling, demolition debris, and equipment operation, including demolition machines and truck traffic. Significant delays or inefficiencies may be unavoidable due to interference and coordination with other site activities.

Soil Management

All soil excavated as part of the HBPP decommissioning must be managed in compliance with various environmental requirements. Due to historical chemical use and past releases of environmental contaminants, such as petroleum hydrocarbons, polychlorinated biphenyls (PCB), metals, and polycyclic aromatic hydrocarbons, the DTSC established specific soil management requirements for the HBPP decommissioning in the Interim Measures Removal Action Work Plan approved in 2009.

All excavated soil must be sampled and analyzed for chemicals of potential concern and compared to soil reuse screening levels that have been established for determining whether excavated soil can be reused as backfill at HBPP. This determination required additional planning, either to conduct pre-excavation characterization of soil samples collected through soil borings, or to collect soil samples from the excavation or stockpiles. Specific requirements were also established for sampling frequency based on the volume of soil generated by individual excavations.

Soil samples must be screened for radiological contamination before any samples are shipped off-site, and if site-related radioactivity is detected, arrangements must be made to ship the samples to specially licensed laboratories that handle licensed radioactive materials. Laboratory analysis generally takes up to 14 days.

To prevent potential cross-contamination, soil must be managed in separate stockpiles until sample results are obtained. The limited availability of on-site space for soil stockpiling was a challenge when multiple excavations are underway, and often required multiple handling as soil stockpiles were moved and combined, where possible, after sample results are reviewed in order to free up additional space for the next loads of excavated soil.

Soil stockpiles or containers must be tracked with respect to the area where they were excavated, their chemical and radiological testing results, PG&E's review of sampling results, the determination of whether the soil may be reused or must be disposed, and its ultimate disposition, including shipment to a licensed disposal facility or the location where the soil was used as backfill on site. Detailed records of all soil management activities were compiled and maintained.

If the results of sampling determined that soil from an excavation must be disposed off-site, additional requirements apply. Saturated soil from excavations below the water table might need to be dried or conditioned with additives in order to prepare it for shipment. Waste shipments had to be appropriately profiled for the planned disposal facility to obtain final approval for shipment. In certain instances, sampling results indicated excavated soil classified as hazardous waste. This status invokes additional environmental compliance requirements related to labeling, storage requirements, and inspections that must be conducted until the waste is shipped.

When excavations are conducted in areas of known environmental contamination, PG&E must perform soil confirmation sampling of the floor and sidewalls of the excavation to verify that the area has been adequately remediated or to document environmental conditions that may need to be addressed later. Based on the results, additional soil excavation may be required. This required close coordination between excavation crews and the HBPP environmental team to minimize delays in completing excavations while waiting for soil sampling results.

In some instances, previously unidentified areas of environmental contamination were encountered during excavations. When this occurred, additional sampling of both the excavated soil and excavation floor and sidewalls might be required, and potentially contaminated soil segregated and managed separately from other excavated soil until sample results can be obtained and reviewed. This often-required additional activities and coordination that were not expected during the planning of the excavation.

Asbestos, Lead, and PCBs

Industry-standard building materials available during the era of HBPP construction were vastly different from those used in present-day construction. The long-term health hazards of working with those materials were unknown or not well understood at the time of construction. Asbestos, mercury, chromate, lead, silica and PCBs are a few of the chemicals in building materials commonly used in the late 1950s and early 1960s. Asbestos, lead, and PCB-containing compounds were popular paint additives and most of HBPP's painted surfaces contain some or all of these constituents. Federal and state regulations for abatement of hazardous or toxic materials are prescriptive and labor and time intensive. Each waste stream was handled and managed differently. This required additional staffing to develop, train, manage, monitor, and report on programs to ensure compliance with the regulations.

Proximity to the Surrounding Community

Unlike most nuclear power plants in the U.S., which are typically situated away from population centers, HBPP is embedded in the King Salmon residential community and across State Highway 101 from an elementary school. The driveway to Charlie Gate, one of two primary plant entries, and employee Charlie Parking Lot are located on a residential street with several homes and a small restaurant. PG&E is sensitive to the quality of life for King Salmon residents, and minimizes abnormal workday activities to restrict intrusion from noise and lights to the extent practical. This requires extra efforts by planners, engineers, construction personnel, and managers to maintain a low profile and sustain good community relations.

E. Costs Submitted for Reasonableness Review

1. General Staffing

a. Summary

General Staffing includes fixed overhead, job functions that are needed regardless of the status and progress of the decommissioning, such as management, safety, environmental, licensing support, procurement and finance. PG&E was attentive to the dynamic needs for staffing by routinely reviewing those needs and tracking actual expenditures against the approved cost estimates. By developing the staffing plan early based on the planned execution of decommissioning and by frequently reviewing needs against actuals, PG&E has been able optimize staffing levels.

The approved General Staffing cost estimate was $36.5 million; PG&E's actual costs were $34.2 million from 2015 through 2018 ($28.1 million is presented for review; the remainder, General Staffing for FSR, will be presented when FSR is completed). General Staffing expenditures for this period were $2.3 million below the 2015 NDCTP estimate, and as discussed in Chapter 8, PG&E forecasts no increase from the previously approved General Staffing cost estimate. As demonstrated by the successful result, PG&E has done an excellent job managing this challenging, complex decommissioning project.

b. Planning

PG&E developed a staffing plan early in the project to optimize staffing levels and ensure staffing was commensurate with the workload. The CWP defined scope provided opportunity for HBPP site management to develop staffing plans for each period through the end of FSR in 2019. Staffing plans included ramp-ups, ramp-downs, durations and funding sources needed to support the staff completing each function associated with the project. These staffing plans were routinely reviewed against the work schedule and approved cost estimates to optimize staffing levels while ensuring the project stays within acceptable budget margins.

Staffing costs included fixed overhead, which includes functions that are needed regardless of field work status and progress. Costs also included direct and discrete labor for personnel who directly support field work and development of work packages and permits. Starting in 2015, staffing costs were split between the base scope (General Staffing) and Caisson, based upon the amount of work being performed.

After completion of the Self Perform Phase, PG&E transferred nearly all the remaining decommissioning scope to the CWC for the CWP. Although the CWC was responsible for scheduling and performing field work, PG&E retained the oversight and monitoring functions. This ensured that the work was completed as safely as possible.

c. Organization

Director and Site Management Team

PG&E recruited and maintained a highly experienced and specialized group of managers with strong technical skills, industry specific knowledge and the desire to see the project accomplished. The combination of PG&E and contractor personnel with specialized skill sets has proven to be cost effective and successful.

Industry evaluations, audits, NRC inspections, health and safety records and project accomplishments all attest to the management team's ability to manage the project within the project parameters. PG&E adopted a staffing mix of utility personnel providing direct line of business influence and contractor expertise not inherent in utility staff. This mix changed over time. Progress into the CWP required more civil structural and contracts type skills. As work was completed, a shift towards FSR and Environmental took place, with specific resources as needed for Strategic Waste.

The decommissioning strategy developed early on by PG&E was critical in the establishment of an overall approach based on industry knowledge, site-specific conditions, benchmarking of available technologies and pairing methods to unique geographical, business and site conditions. The methods and materials for HBPP's construction, limited space and high levels of contamination in some areas posed many FOAK challenges. The management team remained flexible during key activities to overcome many challenges during the CWP, reducing risk and improving overall safety and success of the project.

PG&E management and CWC management worked together seamlessly to understand and address short and long-term needs for infrastructure, site support and laboratory services, regulatory interfaces, permitting, scheduling of concurrent work activities and changing site conditions. PG&E management closely monitored the CWP project schedule and expenditures to ensure the project remained on track and within budget.

Environmental and Site Closure

The Environmental organization was responsible for developing an environmental plan; testing for non-radiological chemical and physical hazards in work areas; characterizing materials for recycling, disposal or processing prior to shipping; identifying residual chemical and physical parameters around the site that prevent free release to public access; preparing and revising environmental and safety procedures and programs; evaluating and obtaining permits for work in areas of cultural, paleontological, and biological significance on the site and surrounding areas; interfacing with concerned stakeholders; developing surveillance and monitoring plans for areas of cultural, paleontological, and biological significance; conducting environmental sampling and remediation sampling to support discharge permits; generating and obtaining approval of revisions to the start permits; conducting environmental sampling to characterize the site and waste streams; and developing remediation and site closure reports.

The Site Closure Manager supervised the Count Room, Corrective Action Program (CAP), Records Management, Training, FSS and the remaining RP staff. Specific activities included: managing and supervising the day-to-day activities of the FSS and Count Room employees; coordinating activities with NRC as required for the LTP; developing and implementing the "Multi-Agency Radiation Survey and

Assessment of Materials and Equipment Manual" (MARSAME) and the "Multi-Agency Radiation Survey and Site Investigation Manual" (MARSSIM); FSS packages for disposition of waste; providing radiological analysis support to RP, Environmental, Radwaste, FSS and LTP; coordinating Quality Assurance/Quality Control with outside laboratories; coordinating the Radiological Environmental Monitoring Plan sampling for HBPP; the FSR plans; and other duties as requested by HBPP's Director for Decommissioning.

Radiation Protection Management Team

The RP organization primarily implemented the requirements of Title 10 of the Code of Federal Regulations (10 CFR) §20 (Standards for Protection against Radiation). The organization also contributed significantly to implementation of the Radiological Effluents Monitoring Program and compliance with Title 10 of the Code of Federal Regulations (40 CFR) §190 (Environmental Radiation Protection Standards for Nuclear Power Operations), Unit 3 Technical Specifications, 10 CFR §19 (Notices, Instructions and Reports to Works: Inspection and Investigations), and the Radiological Environmental Monitoring Program.

PG&E recruited a core group of professional and technician level staff with prior alpha experience, mostly gained at Department of Energy (DOE) facilities. The three principal leaders of the RP Department—the RP Manager, the Site Closure Manager, and the Senior RP Consulting Engineer—had years of experience at DOE facilities or facilities that handle uranium. Ten RP technicians, who were hired for their DOE and alpha experience, were used as lead technicians or as foremen to help the remaining staff understand the complexities of protecting workers from alpha emitting isotopes.

As a result of the decommissioning experience of the RP staff, PG&E instituted use of the following specialty equipment: an alpha effluent monitor for the main stack release point, High Efficiency Particulate Air ventilators, specialty coatings, Gamma Radiation Detection and In-Container Analysis (GARDIAN) gamma spectroscopy system for bulk assay of materials and a variety of engineered controls for alpha airborne activity control.

Decommissioning/Projects

The Decommissioning Organization was responsible for performing cost and budget control, procurement and warehouse functions. The organization was also tasked with oversight, identification and control of project transitions and work.

The Decommissioning Organization interfaced directly with the CWC and oversaw associated field activities. It also tracked the progress of HBPP decommissioning of HBPP, as well as its funding. To accomplish these activities, the Decommissioning Organization assembled a team of very experienced professionals who planned decommissioning from start to finish. The makeup of the Decommissioning Organization changed as the workload declined. The final organization was composed of functional teams including field work and oversight; business, financial and project analysis; and CWP oversight.

Engineering

The Engineering function for decommissioning was embedded in the Plant Director's organization. When work shifted from self-perform to the CWP, the need for a full engineering department was eliminated, and HBPP work control processes also transitioned. A new procedure was developed for use by the primary CWC. The new procedure focused on ensuring that CWP work was clearly defined, thoroughly reviewed, totally transparent and within safety, contractual and regulatory requirements. The procedure facilitated communication with the CWC to ensure that work plans submitted by contractors met requirements so they could be reviewed and approved.

HBPP retained the appropriate external Subject Matter Experts (SMEs) to facilitate review of engineering and work plans. Ramp-down continues as HBPP completes FSR.

Safety

The Safety Program was adopted by the CWC for the day-to-day responsibility of field work safety. The success of the HBPP

Decommissioning Occupational and Industrial Safety Program continued in the CWP of the decommissioning. The prudent measures taken by HBPP to make this a safe work environment for its workers and nearby surrounding public community were effectively adopted by the CWC. HBPP retained safety professionals for oversight and for coordinating with the CWC on work documents and changes to procedures. The decommissioning safety culture continually encouraged a questioning attitude and allowed workers to bring up concerns and think outside the box in order to work safer. Without the adoption of the existing safety culture established by PG&E, starting a new, strong safety culture would have been more challenging.

This accomplishment was evidence of a safety culture, work ethic and continued focus on safe work practices, which was expected by PG&E and CW Management.

Waste

An integral aspect of the overall decommissioning plan at HBPP was a well thought out waste disposal strategy that recognized waste, waste handling and disposal as a major cost driver. PG&E developed strategies focused on disposal options and alternatives that were well integrated into long-term planning. Disposal pathways and means and methods were built into the work packages in the field.

The team identified waste extraction routes that maximized efficiency and minimized risk by establishing waste paths that minimized interference with current or future work progression within the buildings and site footprint. Developing the strategies involved many interfaces with the CWC, various area work crews, riggers, waste receivers, packagers and RP. Considerations were made for adequate waste laydown and packaging areas that limited contamination and exposure risks. Site coordination that accommodated waste movement but did not interfere with other decommissioning activities was required.

Count Room

The Count Room performs detailed laboratory analysis of radiological samples. The Count Room is certified for: identification and reporting of radiological data for inbound and outgoing shipments;

radwaste tank discharge, GWTS, and loop drain sampling; storm water and well monitoring; environmental monitoring; Department of Transportation-exempt shipments; and whole body counting of personnel. Analyses include gamma specs spectroscopy, alpha/beta counting, and radiochemical analysis of hard-to-detect isotopes. Typically, samples include work space air and breathing zone air, water, and soil samples and smears from normal routine and job-coverage RP activities. The Count Room performs a variety of necessary functions for the RP, FSS, Environmental, and Strategic Waste Departments.

Much of this work is mandated by 10 CFR §20 (Standards for Protection against Radiation), with additional requirements imposed by 10 CFR §50 licensing conditions, the License Termination Plan, EPA regulations, and specific offsite burial site requirements. The Count Room is responsible for analyzing work area and environmental samples for radiological constituents; calibrating and maintaining instrumentation; conducting bioassay sampling and internal and external dose assessments; evaluating emergent radiological hazards; developing, in coordination with other departments, As Low As Reasonably Achievable (ALARA) reviews and controls; evaluating post-decommissioning area status relative to Derived Concentration Guideline Levels (DCGL) for buildings, soil, and groundwater; and generating reports to the NRC and state of California regulators.

<u>Programs</u>

General Staffing also captures a number of work related programs including Safety, Licensing, Enterprise Risk Program, CAP, Work Control, Technical Evaluation Documents, Investment Recovery and Procedure Manuals.

2. Remainder of Plant Systems

a. Summary

The Remainder of Plant Systems cost category includes Direct Labor (Craft, RP); Liquid Radwaste (LRW) removal and associated Tools and Equipment. The work followed a prescribed sequence and methodology to ensure a comprehensive, safe and cost-effective approach to decommissioning.

Actual costs were $4.6 million compared to the approved cost estimate of $5.3 million for this period. In addition, $42 thousand in direct labor during 2012 through 2014 is presented for reasonableness review.

b. Direct Labor (RP)

The focus and purpose of the RP organization was the protection of the workforce, public and environment from potential deleterious effects of exposure to radioactive materials and ionizing radiation. The RP organization accomplished its mission through a combination of monitoring, measuring and controlling radioactive materials and access to those materials.

The RP organization was divided into several functional areas. RP Technicians provided all required RP functions and RP Deconners maintained cleanliness and prevented contamination from spreading throughout the plant and to workers required to be in contaminated areas. These combined teams of RP Technicians and RP Deconners provided all required job coverage, including performing routine and special surveys, manning the radiological control points for each of the processes and activities and ensuring that radiological dose and contamination remained in a controlled environment.

HBPP RP rules and practices were established in accordance with NRC regulations and PG&E Company Policy, which provided for the safety of HBPP workers occupationally exposed to radiation.

The following section and section E.7.g. provide a representative sample of the complexity of the work which this project entailed.

<u>East Yard Excavation</u>

There were two LRW lines buried in the East Yard. One was an abandoned radwaste line, which discharged into the circulating water discharge; and the other was a tank discharge line, which traveled under the road to the Discharge Canal. There were quantities of radioactive contamination still in those lines, which required careful monitoring and handling to avoid unintentionally spreading contamination during removal.

c. Tools and Equipment

Typical tools and equipment purchased to support the decommissioning project included many general tools of varying sizes, such as wrenches, hammers, screwdrivers and drills, as well as electrical equipment, carpentry materials, various cutting equipment, replacement blades, pipe fitting tools and Personal Protective Equipment (PPE). Most small tools and equipment were kept in tool cribs in order to maintain control of the inventory and to control potential contamination issues.

This work was assumed by the CWC when PG&E turned the tool program over in 2015 and it generally covered costs through the remainder of the CWP. A separate procurement group under PG&E remained in place to purchase contamination-control provisions, various lab supplies, contamination detection instrumentation and other specialty-customized materials required during the decommissioning.

Most small tools and equipment were kept in tool cribs in order to maintain control of the inventory and to control potential contamination issues. Two tool cribs were established early in the project, one located within the RCA to service potentially radiologically-contaminated tools, and one outside of the RCA, dedicated to non-radiological work activities. The purpose of tool cribs was to provide, maintain and control the necessary hand tools and personnel safety equipment required for workers to perform daily field activities. Tool cribs were staffed to ensure that adequate tools in safe working order were available when needed. Staff also conducted inspections, maintenance and distribution of necessary safety equipment.

The tool crib and rigging loft located inside the RCA were closed and removed in 2015. As the station approached down-posting the RCA in preparation for Open Air Demo (OAD) of the Reactor Building, a process was established to evaluate the radiological condition of the tools and equipment inside the RCA. By the very nature of the usage of the tools and equipment, fixed contamination became the overarching concern and the majority of the tools and equipment used during decommissioning were not in condition to be free released.

Radiological tools and supplies consisted of an adequate variety and supply of materials for radiation and contamination detection, isolation, controls, health physic supplies in support of decommissioning and the typical hand tools and PPE inventories specific to decontamination tasks. This included calibrated instrumentation; calibration services; instrumentation maintenance; waste-handling materials and storage; contamination-control devices; various signage and boundary materials; and sampling supplies.

PG&E continued to realize cost savings from the used radiation detection equipment obtained from the Rancho Seco Nuclear Power Plant decommissioning project. As instrumentation aged or was damaged from infield work, legacy parts were utilized from the used instrument batch to refurbish and maintain an ample supply of functioning instrumentation required to monitor remediation and decommissioning activities, thus reducing the need to purchase replacement equipment.

PG&E was also able to reduce costs by reusing existing tools and equipment from completed projects by repurposing and modifying the tools for future work.

PG&E implemented a few key changes to strategy as decommissioning progress. These resulted in optimizing RP tools and equipment. Two significant items were the GARDIAN system for reuse of soils on site and the OAD process.

The GARDIAN system is a series of sensitive radiation detection instruments designed to survey large volumes of containerized waste or homogeneous material for the presence of radioactivity. The GARDIAN system is discussed in detail in Chapter 9, Attachment A, HBPP Completed Projects Review, Section 4.1.1.6.2.

OAD allowed for the rapid, controlled demolition of structures and removal of large volumes of waste materials for disposal.

To meet OAD threshold levels, radiological safety required encapsulation of some contaminated surfaces such as walls and floors, as well as the inside of embedded piping and components. The RP organization continued to research and implement new, effective cost-saving methods, such as the use of off-the-shelf alternatives to encapsulate, which met the Waste Acceptance Criteria (WAC) for the waste disposal site.

Ultimately, contaminated tools and equipment were discarded as waste. Approximately 90 percent of the tooling was discarded due to fixed contamination. Virtually 100 percent of the rigging was discarded, as the rigging could not be easily confirmed as radiologically clean. The balance of the radiologically-cleared tooling was placed in the tool crib outside of the RCA for general use on the project.

3. Specific Project Costs

a. Summary

Specific Project Costs included the Reactor Vessel Removal, which was submitted and approved in the 2015 NDCTP, and FSR. FSR work is scheduled to be completed in 2019, and the $40.4 million in incurred costs FSR is not included here. The balance of Specific Project Costs is comprised of three demolition projects and facilities removal performed by the CWC: Nuclear Facilities Demolition, Offices and Facilities Demolition and Other Services. The 2015 NDCTP approved estimate for these three projects was $78.0 million and actual expenditures were $78.67 million, less than a million ($621,000, or 0.8 percent) over the estimate. The primary challenge to meeting the budget was the work conducted on the Units 1, 2 and 3 Circulating Water Lines, discussed below.

b. Civil Works

1) Nuclear Facilities

Nuclear Facilities was comprised of Restricted Area Preparations; Refueling Building (RFB) demolition; Units 1, 2 and 3 Circulating Water Lines removal; Upper Yard Demolition; and Temporary Facilities removal.

Administration Services

Administration Services describes project overhead staffing and fixed costs incurred by the CWC including indirect costs, which could not be directly assigned to specific decommissioning activities. Examples of these costs include trailer rentals; van transportation, including rentals and fuel; housekeeping activities, including tree services, bottled water services, lawn care and landscaping, garbage services; Management travel; incidental expenses; and subsistence.

Restricted Area Prep

Three demolition projects, the Turbine Building, the Liquid Radwaste Building (LRWB) and the Security Alarm Station (SAS) Building, comprised the area surrounding the RFB and Caisson. Their removal, and the removal of the underground utilities in the vicinity, was a precursor to starting the underground demolition of the RFB, the spent fuel pool (SFP) and the Caisson. This was referred to as Restricted Area.

Restricted Area Prep – Turbine Building Concrete Demolition

The Turbine Building was located adjacent to and south of the Reactor Building and housed the steam turbine connected to a generator with its condenser, heat exchangers and other auxiliary equipment integral to the operation of the generating facility. All components were removed during the self-perform phase of the project, leaving the structure and embedded pipe for the CWC removal phase. The Turbine Building foundation was partially demolished in 2014-2015. The below-grade foundation was temporarily left in place. Removal of the foundation and Caisson was planned for concurrent execution, as the area would have been within the slurry wall containment to allow for dry removal. The work package (WP) Planner and Job Supervisor carefully laid out a 3-phase plan, which minimized disruption of surrounding activities and integrated with the concurrent CSM pre-trenching and installation.

The underground structure was a heavily-reinforced concrete structure that sat on top of creosote foundation piles driven into the soil. Some walls in the large, irregularly-shaped basement were up to 30 inches thick and the floor varied from 3 feet, to nearly 10 feet thick at equipment pads/pedestals.

The scope of work exceeded a typical subsurface removal activity. A geotechnical engineer was engaged to perform an analysis due to the depth of excavations, presence of groundwater and types of soil. This analysis provided the CWC with a technical approach for excavation sequencing, stability and groundwater and surface water control.

Early in the project, a change to the excavation plan was needed to address the deep foundation pile removal below the Turbine Building foundation, outside the water CSM water cutoff wall required for Caisson excavation. Engineering prepared a Design Change Notification, which imposed a limitation on the number of open holes from pile removal were allowed at any given time, with the requirement that each group of holes had to be filled with a cement slurry mix before another group of piles could be removed. The plan also required the installation of sumps and pumps to help manage the subsurface water that emerged as the piles were pulled out. This water had to be analyzed for radiological contamination and processed through the GWTS.

This scope of work included removal of below-grade pedestal structures, timber foundation piles, imbedded utilities, drains and intake and discharge piping up to 54 inches in diameter. Removal processes had to incorporate these oversized foundations, numerous deep piles and contaminated utilities. Excavated soil was checked by RP to determine the appropriate type of waste containers. Waste Management would then direct packaging, shipment schedules and field and administrative logistics to and from work faces.

Critical path work sequencing was a priority and necessitated a phased approach of field implementation. Significant portions of the foundation were an impediment to beginning and completing the CSM wall installation.

Between completion of the above-ground demolition in August 2013, and the beginning of foundation demolition in April 2015, the area was used for equipment and material laydown. The final backfill and FSS was completed in March 2016.

Restricted Area Prep – Liquid Radwaste Building

The LRWB was located on the HBPP site to the north of the RFB. The LRWB was connected to the RFB by an underground tunnel, which supplied all required instrumentation, piping and original ventilation to the concrete structures and tanks for operation. During HBPP's operational period and while in SAFSTOR, Turbine Building and RFB waste systems and associated drains were sent to the LRW system for processing and final disposition.

A concentrator, demineralizer, filters, pumps and their associated piping connected eight tanks into one integrated system. During operation and SAFSTOR, this system processed radioactive wastewater for release, collected radioactive byproducts on filter media and demineralized the water as it passed through resins. The resins and filters were collected, packaged and disposed of at offsite waste facilities.

Most of the LRWB's interior components were removed during the PG&E self-perform phase of the project, before the CWC began work. This work was evaluated and approved in the 2015 NDCTP.

The original LRWB had an open-air layout, which consisted of a concrete slab featuring drains and trenches for control of liquids. The LRWB had a heavily-reinforced concrete foundation built into a hillside and covered 4,400 square feet in total. The concrete walls were up to 3 feet thick and the slab was up to 3.5 feet thick. The foundation was supported by concrete piers, installed as part of the original structural design. A metal enclosure was installed around the LRWB during SAFSTOR to provide containment, weather protection and contamination control of the LRW systems and concrete structures. The LRWB required extensive decontamination of the interior concrete walls and floor surfaces prior to OAD. Controls required High Efficiency Particulate Air ventilation, tents, glove bags, enclosures, fixatives, wetting, decontamination, remediation and packaging. In addition to radiological contamination, other hazards had to be mitigated including lead, asbestos, PCBs and mercury.

Ventilation to the metal enclosure was supplied by the Main Plant Exhaust Fan (MPEF). The metal enclosure was a one-story, six-bay, pre-engineered rigid-frame steel structure with metal roofing and metal siding. The footprint of the metal enclosure covered the footprint of the LRWB.

Demolition to the interior of the LRWB started in January 2015 and finished with removal of the exterior conduit and lighting in July 2015. Demolition of the metal enclosure started at the end of July 2015 and finished in August 2015. The building foundation and buttress walls were kept in place as a retaining structure for the Upper Yard. Demolition of the LRWB's concrete structures started in May 2016. Subgrade excavation, soil remediation under the foundation and backfill was completed in August 2016, two years ahead of baseline schedule. Rescheduling this activity allowed for avoidance of costs associated with twice remobilizing RP resources needed to assure the radiological safety of the workforce and environment during wall and foundation demolition.

<u>Restricted Area Prep – Security Alarm Station</u>

The SAS was a 30-foot by 30-foot heavily-reinforced concrete superstructure, with support section below grade. The SAS was located just north of the RFB and south of the LRWB, inside the RCA. The SAS facility was originally built as a hydrogen recombiner vault to reduce radiation emissions leaving the stack of the HBPP Unit 3 nuclear facility. This vault was built prior to the 1976 refueling outage but because the plant was never restarted, the vault was never placed into service and remained a clean area.

The SAS superstructure consisted of a roof, walls and floors as thick as 2 feet 9 inches. Below grade, the SAS consisted of walls that were up to 3 feet thick, with a 2-foot thick floor slab. Access to the structure was through an entry opening into a stairwell down to the main floor of the structure. The east wall provided access into a pipe tunnel.

The interior of the structure included a vestibule on the ground floor and both a large and a small room, hallway and storage on the lower floor. The SAS was connected to the plant ventilation system through the Off Gas Tunnel. The southwest corner was within a few feet of the MPEF foundation and associated ventilation ducting and filter bank. These ventilation components were quality-related and needed to stay in operation. The LRWB ventilation duct was routed over the top of the SAS and was removed prior to demolition of the building.

The SAS demolition work was split into two separate evolutions, Above-Grade Demolition and Below-Grade Demolition, which were separated by five months. This phased approach was implemented to enable more effective coordination with other demolition activities, specifically, pre-trenching related to the CSM installation.

The concrete rubble from above-grade demolition was placed into the SAS lower level as a temporary fill. The remaining voids were filled with flowable fill, or reusable fill from the site.

The demolition followed standard demolition practices but required close monitoring of the in-service MPEF. Coated concrete was segregated and characterized through paint sampling, then packaged and shipped off site to an appropriate waste facility. Any uncoated concrete (roof and upper sections of the SAS walls) was rubblized and used as temporary backfill. Above-grade work of the SAS began in September 2014 and was completed on schedule in October 2014.

Once the slurry wall pre-trenching critical path work was completed north of the SAS footprint, the SAS below-grade work commenced. Work began in March 2015 and was completed in

April 2015, concurrent with the planned North Yard work in April 2015. The CWC analyzed the work schedule and determined the planned productivity of the SAS below-grade work could be optimized by utilizing crews in adjacent work areas performing other work, without affecting the scheduled critical path. The overall duration of the SAS below-grade work was reduced, therefore minimizing planned mobilizations, planned demobilizations, crew production time and equipment rental time.

The slurry fill that was used to cap the area during above-grade demolition was easily removed, then below-grade walls and rubble from above-grade demolition was removed, using similar equipment as in the above-grade demolition. The removal had to be completed in phases using engineered slopes to ensure the MPEF foundation was adequately supported.

When a depth of approximately 6 feet was reached, pumps and sump areas were put in place to remove the existing rain and groundwater collected in the area. These pumps remained active throughout the rubbling process.

Close coordination with the RFB abatement project was required to complete backfill of the excavation, upon which RFB scaffold erection was dependent.

<u>Refueling Building</u>

The RFB was a rectangular concrete structure constructed over the Caisson. It was approximately 100 feet long by 45 feet wide by 45 feet tall and constructed of reinforced concrete. The structure served as the ventilation and containment envelope for the SFP and Caisson support systems. It also served as secondary containment for the reactor. MPEF and components were attached to the RFB. The MPEF originally exhausted through the stack. The main portion of the stack was removed during SAFSTOR operations and the stack base was located immediately north of the RFB.

The initial commodities removal and hazard remediation of the RFB was performed during the self-perform phase of decommissioning. The HBPP Team turned over the balance of

RFB demolition to the CWC in 2014. The remaining tasks to prepare the RFB for OAD included drywell systems remediation and removal, MPEF components remediation and removal, plant stack base demolition, overhead crane removal and asbestos abatement of the exterior.

In order to prepare for OAD, a complete characterization for radiological and environmental hazards was completed. The systematic, level-by-level characterization approach evaluated all rooms and areas within the RFB and Caisson proper including piping, penetrations and concrete surfaces. Systems that did not meet the required OAD criteria were removed, remediated or placed in a configuration that met OAD criteria. Additionally, the exterior asbestos containing coating and roof membrane had to be removed as well as partial dismantling and preparation of the overhead crane for removal.

RFB wall demolition required an extensive study and approval process for asbestos abatement methodology. The removal work required erection of a sizable engineered scaffold structure on the exterior walls of the RFB, which was shrink-wrapped to establish negative-pressure asbestos containment on the building exterior, allowing for the RFB rhino coating to be removed. The scope of OAD included above-grade demolition of the RFB to the working surface grade located inside the Unit 3 footprint.

In order to accommodate the critical path CSM preparation, the MPEF and the RFB east 40 feet were selected as the starting point of the RFB OAD. A demolition contractor familiar with demolition of radiologically-contaminated structures was selected to begin the OAD. The contractor was able to successfully demolish the MPEF and the east 40 feet of the RFB in October 2015. As expected with an OAD determination, the OAD was executed without personnel injury or uptake of any radiological material. Waste was downsized as needed and packaged per direction of Waste Management.

The remainder of the RFB and the stack base were demolished, using the same techniques as on the RFB east 40 feet and the

MPEF. This demolition work was also executed without personnel injury or uptake of any radiological material. Waste was downsized and packaged by Waste packaging personnel. The SFP was filled with concrete rubble to create a working surface in the structure, so heavy equipment could operate over the pool area during future Caisson removal. Concrete rubble was used, as it was in the immediate proximity and saved the hauling expense of other fill materials.

Rather than a piece-by-piece overhead cut and lower operation, an engineering design planned a careful and controlled drop of the entire overhead 74,000-pound bridge crane assembly. It was performed flawlessly, providing a much safer means of removal and saving considerable crew time.

Miscellaneous excavation included removal of the Off Gas Tunnel and other below-grade structures and piping systems, rigging and removal of 70-foot long steel piles encountered under the slab.

Units 1, 2 and 3 Circulating Water Lines

The Units 1, 2 and 3 circulating cooling water lines were located underground between the Intake Canal structure and the Discharge Canal structure. The pipes ranged in depth from approximately 8 feet Below Ground Surface (BGS) to 20 feet BGS.

The circulating cooling water lines needed to be surveyed and found radiologically "clean" to meet the NRC standards for clean-up of a decommissioning nuclear site for release of the 10 CFR §50 License. Early estimates anticipated leaving some of the pipe in place and using trench boxes to remove individual pipes. Interior surfaces were found to be too difficult to clean and survey and the history of radiologically-contaminated water spills into the storm drain system and subsequently into the Intake Canal led to the decision to remove the pipes. Schedule impacts of removing one line at a time led to the decision to use sheet pile as the Shoring of Excavation/Support of Excavation (SOE) and completely remove all the circulating water piping.

After the decision was made to proceed with removal of the pipes, difficulties arose regarding the availability of sheet pile. In February 2017, a major storm with significant rain caused a breach in the main and emergency spillways at Oroville, CA. Due to the significance of this emergency situation, major supplies of steel materials, including sheet pile, were being diverted to repair the dam. This created a shortage of supplies in the western U.S. and delayed delivery of the materials.

The pipes were removed in four major phases. First, approximately 1,380 linear feet of reinforced concrete pipe and associated thrust blocks was demolished and removed in Phase A. The first 1,000 feet of the piping did not require a shoring system as the pipe was approximately 8 feet below grade. A combination of sloping and benching methods was used to remove the remaining 380 feet of pipe in this section, which was approximately 20 feet below grade.

Phases B and C of pipe removal included the demolition of approximately 400 linear feet and 350 linear feet, respectively, of reinforced-concrete pipe and its associated thrust blocks for Units 1, 2 and 3. These pipes were approximately 20 feet below grade. Due to the proximity to Humboldt Bay Generating Station (HBGS), sloping and benching could not be utilized for removal. Instead, the CWC used a sheet pile shoring system to reach the proper depth and minimize groundwater intrusion. Shallow commodity removal was performed prior to sheet pile installation. Phases B and C excavations included the removal of approximately 2,784 cubic yards of soil and 3,221 cubic yards of soil, respectively.

Phases B and C encroached on the HBGS footprint and required a substantial amount of coordination to minimize impact to operations. Engineering performed analyses of soils near the operating power plant and determined no concrete or equipment were at risk from sheet pile installation vibrations. Pre-auguring the pile locations lessened the vibrations and supported driving the sheet piles. Vibration monitoring was conducted to assure HBGS

Plant Operators that shoring installation vibrations were within the parameters of equipment in their plant. Continuous operation of HBGS is a requirement for maintaining system grid stability. Phase C excavations included the removal of approximately 3,221 cubic yards of soil.

Phase D included the demolition and removal of approximately 250 linear feet of reinforced-concrete pipe and its associated thrust blocks. The pipes were approximately 20 feet below grade, which required the sheet pile engineered shoring system to reach the proper depth and minimize groundwater intrusion. This section also included a 4-inch clay discharge pipe that was known to be radiologically contaminated. This pipe ran from the LRWB to the Discharge Canal. Phase D excavations included the removal of approximately 4,830 cubic yards of soil.

During installation of sheet piles, ground conditions were discovered to be more difficult than anticipated. The lower clay layer was very tight, necessitating extensive pre-drilling to drive the 56-foot sheets to refusal in the clay layer, as required in the shoring design. The sheet pile driver was also equipped with a drill rig. A series of holes were drilled spaced along the alignment of the sheet piles. This process facilitated easier sheet-pile driving and reduced disruptive vibration to the nearby HBGS. Pre-drilling the holes extended the original sheet pile installation schedule, but reduced the time to drive the sheet piles to the required depth.

The depth of circulating water piping between 8 feet and 20 feet BGS resulted in groundwater intrusion and constant in-flow water from an underground spring near the Discharge Canal headworks, facilitating a constant need to dewater the excavations to complete the work. Excavations were dewatered by submersible pumps daily, conveying water to the GWTS. In addition, the 6-inch main pipeline that was used to transfer water from other excavations to the GWTS was originally routed across the Phase D area and required rerouting around the area to facilitate the excavation.

The upper few feet of the Discharge Canal headwall were removed under the Discharge Canal project. The circulating water pipes were embedded in this headwall at such a depth that safely removing them during the Discharge Canal removal without an engineered shoring design was not possible. Working the remnant headwall with the circulating cooling water piping allowed efficient use of the deep shoring needed and required only one mobilization effort of the equipment. This also prevented the need to close Decom Road, which would have had unacceptable impacts to the schedule at that time.

The location of the circulating water piping required substantial coordination with other projects. A section of piping south of the Discharge Canal headwall was located under a major throughway for waste streams from the Caisson excavation project to the Soil Management Facility (SMF) tents. Work crews were required to construct an alternate truck route to facilitate these other critical path projects. A bypass road was constructed at the north end of the Discharge Canal to allow the crew to complete substantial excavations at the south. This required installation and compaction of a 20-foot wide road base.

The oily water separator was a defined feature of work requiring removal. Its location next to the circulating cooling lines made removal simultaneously with one of the adjacent phases of work practical but extended the duration of the circulating cooling water piping project. The work included above-grade commodities, four deep pits, piping and concrete rubble.

<u>Upper Yard Demolition</u>

The Upper Yard was a 20,000-square foot area within the RCA at the north side of the site, midway between the ISFSI and the Discharge Canal. The entire area was paved over with asphalt and used for various storage needs until the beginning of demolition. Buildings within the Upper Yard included the Low-Level Radwaste Building (LLRWB), the Solid Radwaste Building (SRWB), the underground High-Level Radwaste Vault (HLRWV) and some of the temporary office and support structures for the decommissioning work. Though originally planned to be executed as four separate projects, they were directed by one supervisor and field engineer and completed concurrently using the same crew and demolition equipment. The result was enhanced efficiency in execution.

The LLRWB demolition included removal of the transite board demountable partitions by a specialty abatement contractor, designated as Class II materials. During hazardous material removal, potential friable asbestos was discovered between transite panels. Mercury-vapor lights, mercury switches and PCBs were removed by qualified remediation specialists and approved for disposal.

After asbestos abatement was completed, demolition of the LLRWB followed standard demolition practices, with the majority of the work being performed using an excavator fitted with either a hydraulic breaker (hammer) or a concrete processor. Separation of concrete and rebar was required before wall debris was loaded into Intermodals (IMs) for disposal.

The SRWB commodity removal phase of work included a detailed radiological survey of the entire building, including the rafters and drains, to support the waste and building characterization. Since this building housed solid wastes stored in appropriate containers, there was little remediation to perform. Hazards abated during interior prep work were mercury switches and mercury-vapor and fluorescent lighting. Remediation debris was loaded into suitable containers. The loaded containers were transferred from the work area and consolidated into larger waste containers for removal from the site. Existing in the building was a 2-1/2-ton overhead trolley hoist and rail. A man-lift was brought into the SRWB to drain oil from the hoist gearbox and assist in its removal.

The SRWB was demolished methodically, bay-by-bay utilizing large excavators equipped with metal-cutting shears and bucket/thumb attachments. Multiple excavators were employed throughout the demolition process, ensuring positive control of building components.

Prior to the start of the HLRWV demolition, the HLRWV and nearby LRWB foundation were evaluated for ground pressure of demolition equipment against the remaining below-grade walls for both structures. A key feature of the LRWB foundation was an integral retaining wall supporting the Upper Yard slope. As equipment was working on the north side of the LRWB foundation, a concern was identified that the retaining wall integrity would be diminished and potentially lead to slope failure. In addition, as demolition began on the HLRWV, the structural integrity and ability to support heavy equipment on the surrounding soils were reduced. Engineering evaluations were performed on both underground features to provide setback distance for equipment expected to approach those areas. An OSHA engineering survey was also performed to evaluate the sequence of demolition and its potential for a premature collapse of a wall or beam. To keep heavy equipment from affecting nearby below-grade walls, crews placed safe work zone flagging around the areas, which designated two offset zones.

In order to prepare for the HLRWV demolition, the lids were removed from the HLRWV and the chambers were emptied of high-level contaminants, including stainless steel liner pans and a drum of waste. RP characterized the walls and floor. The drain line under the HLRWV was found to be radiologically contaminated, as were the soils around it. RP assisted with samples, then plugged the drain. Remaining radiological spots of concern were remediated or fixed and permission was given for OAD.

Demolition of the HLRWV began as a continuation of the subgrade commodities removal. The soil surrounding the sides of the HLRWV was removed and then the sides and bottom of the HLRWV were demolished, using an excavator fitted with either a hydraulic breaker (hammer) or a concrete processor. The drain line from the floor of the HLRWV to the LRWB was a deep feature, asbestos-containing 4-inch diameter transite pipe with radioactive contaminants interior to the pipe. Contaminated soils under the pipe were processed for disposal. Separation of concrete and rebar was required. The three HLRWV lids, stainless steel liner drain pans, and concrete walls and floor were loaded into IMs for disposal.

Once the buildings and slabs were removed, excavation and removal of the remaining underground utilities were required. Upper Yard asphalt was removed and the soils were tested by RP, followed by removal of the below-grade commodities.

Subgrade commodity removal included the fire water main (part of which was transite pipe) and standpipe riser removal, which were performed simultaneously. A portion of the storm water drain line was abandoned and removed. A sump and pump were installed to pump storm water. Conduits from load center and building-to-building were checked live/dead/live, and removed as encountered. A 4-inch radwaste clay drain line from the corner of the LRWB out to the road was removed. A 12-inch natural gas line, which was found to have asbestos-containing wrap, was removed in 10-foot sections. RCA Way had to be kept clean using a skid steer and road sweeper to prevent the spread of mud. The SWPPP) crew maintained Best Management Practices (BMP) to prevent sediment runoff.

Asbestos containing material (ACM) in this area included transite water lines, a transite fire water line, transite drain lines and other ACM-coated piping. This required a large amount of machine and labor time to be spent on careful removal, sizing, wrapping and loading into double-lined containers. ACM commodities were abated using an asbestos abatement specialty contractor.

Low levels of arsenic were identified at three locations in previous surveys of the Upper Yard, along the RCA Way roadway at the east side of the yard. These areas were remediated and the wastes disposed of following the direction of environmental specialists.

The CWC coordinated removal of the LRWB north foundation wall with grading of the south portion of the Upper Yard to ensure proper water runoff and to provide a safe 1.5:1 slope. As soils were tested, some went to reuse storage areas and the remaining soils were loaded into IMs for disposal. RP marked areas that required remediation. The steep embankment north and east of the LRWB was included in this demolition, which also included removing the shotcrete and soils to provide an even slope down to the CSM work area. An FSS was performed over all areas where commodities were removed.

Temporary Facilities

The activities comprising this scope were performed to support soil management and were broken down into three key projects: SMF installation and subsequent foundation removal and demobilization; GARDIAN system installation; and power pole relocation.

SMF tents served to keep soils controlled and aided in containment of water draining from the soils, which could have potentially released contaminants. The slabs below the SMFs were designed to support the weight of soils and heavy equipment. Large doors at either end provided effective airflow, which assisted with soil drying processes and offered the ability to move end-loaders and dump trucks through the tent structures.

Each structure provided a 200-foot by 100-foot external footprint. The size and dimensions required engineering for structural footings, slab, tent structures and coverings, including drainage water management and an electrical power supply. The best location for the tents was determined to be in the area that previously housed office trailers for decommissioning, which was at the far eastern end of the site. This location was selected because of its close proximity to the Discharge Canal, circulating cooling water piping and Caisson excavation.

The tents were located parallel to each other with a 10-foot separation. The steel supports and roof structures endured rigorous engineering analysis, in light of the seismic building code, the North Coast 100-Year Storm Requirements and personnel safety. A local consulting civil engineering firm was engaged to design the concrete footings, slab and curb. The structures were designed by the supplier and approved by local building authorities. A land surveyor performed the layout and the final elevation certificate for flood insurance.

Rigging plans were created and approved, which required the use of a crane to bring the heavy roll of fabric up and over the 38-foot high truss structures. Man-lifts and other equipment were used for spreading and attaching the tent fabric to the frames and for mounting large door frames to the structures.

SMF 1 tent was used for soils with some radiological activity and SMF 2 tent was used for “clean” soil. Water drained from the soils was collected in a below-grade tank at the east end of each building and pumped to portable totes. Water from radiologically-impacted soil was collected and shipped off site for treatment, as required. After sampling, water from the “clean” soil was transported to the GWTS for treatment.

Complete removal of the SMF was required to place the site in final configuration, which included the start of FSR, wetland establishment, FSS and NRC §50 License Termination. Once the characterization survey of the SMF 2 fabric and frame was performed, they were removed by high-reach excavators and man-lifts. Tent fabric and structure had to be disposed of as waste. The concrete slab and footings were surveyed and abated if necessary, broken up by conventional demolition means and taken to the processor to be rubblized for Caisson fill material.

The soils under the tent were sampled for radiological and chemical contamination, then underwent minor grading to bring them level with the surrounding area.

The SMF 1 was removed later in the same fashion with no incidents. The grounds were then available for reconfiguration, per FSR requirements.

A sewer lift station had been added in this general area to support numerous offices. Due to its proximity, it was removed at the time of removal of the second SMF facility. The remaining piping was also removed and disposed of.

The GARDIAN system allowed scanning and detection of the radioactive content of soil, and eventually concrete, to assist in classification of the material. The GARDIAN system supported efforts to classify material for reuse instead of waste, which was disposed of at a high cost. Rather than purchasing new material, reuse material could be utilized on the site to backfill areas when removing Caisson components or other site excavations. The GARDIAN system was used for the large amounts of excavated soil on nearly the entire site. These soil quantities were placed in varying-sized dump trucks, each requiring its own calibration, settings and run-time based on container size and material composition of the soil in the container for final disposition. Bulk scanning of truckload quantities for radiological activity reduced labor hours for RP and the FSS. The alternative survey method was to use the In Situ Object Counting System (ISOCS) and walkover surveys to release site soils for FSS. The ISOCS system was labor-intensive for bulk soil surveys. Both these processes were used during decommissioning and FSS release of site areas. However, the GARDIAN reduced RP and FSS labor costs and shortened the time to perform soil assays, since the entirety of material in a surveyed container could be assayed at once.

The GARDIAN assay system included two semi-trailers, which housed and provided support system equipment and instrumentation, as well as providing a transportation means for the temporarily-leased equipment. Installed in both trailers were detector tracks and towers, which were used to position the High-Purity Germanium Detectors at correct spacing and height. These detectors required cooling by liquid nitrogen for proper operation and were adjustable for various sizes of trucks and containers.

The spacing of the two trailers allowed approximately 2 feet of clearance on either side of a typical 8-foot wide load. An in-ground calibrated truck scale was installed between the two detector trailers, allowing the load to be weighed as required before the scanning process started. Power, communication and liquid nitrogen were also supplied to the trailers. In addition to supplying the utilities to the site, a pad area of approximately 60 feet by 45 feet was excavated, leveled and surfaced. Stairs and a landing were added by site carpenters, providing safe access to the trailers and operating systems.

The installation area was chosen for traffic control and low-radiation background activity. The tight confines of the small site played a key role in the location of this equipment and required detailed traffic control plans as the materials were moved around the site. This system was at the far west end of the Owner Controlled Area, directly in front of Gate C. This became the main entry and exit site for waste and material shipments. This industry-accepted tool was used at near-capacity on days of excavation and waste packaging.

To survey a dump truck with a load or mounted container, the truck drove slowly between the system trailers to allow a scan of the load by the scintillation detectors. After the truck's load cleared the detectors, the truck stopped in a pre-designated position between the trailers to allow a fixed-position assay, using ISOCS to qualify and quantify gamma emitting nuclides present in the load. Total scan time for this process varied by truck volume but averaged about seventeen minutes per 10-cubic yard truck.

The start-up of the system was performed by a qualified vendor who trained on-site personnel to operate and maintain the GARDIAN. The system required scheduled calibration and testing during its operation at HBPP.

Based on scheduled active excavations that would be taking place at the same time, the CWC's foresaw a pinch point approaching when more than thirty trucks per day were going to cross the GARDIAN. Thirty trucks would consume over 8.5 hours of scan time, thus slowing the movement of soils around the site and risking schedule delays while waiting for the equipment to become available for use. Specific work taking place included canal, circulating water line removal, Caisson removal and the beginning of the FSR area modification, all creating excavated soils, which needed to go through the GARDIAN system. A second GARDIAN system was ordered and installed to reduce potential delays in moving soils.

Space limitations and active field work taking place at time of installation effectively eliminated all possible locations for the second GARDIAN system, except in the area next to the first system. De-staffing allowed for the removal of an office trailer, and the installation of the second GARDIAN took its location with its layout similar, and parallel to the first one. Required office staff was relocated to both on- and offsite locations to accommodate this change.

The maximum capacity of one system was 32 trucks per day. This maximum was reached a number of times before the second system became operational. The height of operations saw more than 64 trucks per day on extended-hour days.

Power pole relocation eliminated potential electrical hazards to excavation equipment. This project served a dual purpose of clearing unneeded distribution lines and making for a safer workspace above the canal stockpile. At the east end in the Discharge Canal area, some of the 12-kilovolt (kV) power line poles and cable interfered with the safe operation of high-reach excavation equipment working the CSM stockpiles in the canal. Eventual site restoration called for removing some of these poles and lines.

PG&E’s Distribution Line Department performed most of the work, with coordination among Engineering and Planners. The Line Division prepared work instructions and the CWC prepared a document with guidelines for supporting PG&E’s work with labor, supervision, RP and waste coverage.

As this was the only power supply line to the site, coordination of a site-wide power outage was necessary. Critical path work was supported by generators and the schedule minimized interruption to field work by scheduling the required site power outage over a weekend. A list of safe work steps was written to protect workers and those on site not directly involved. Once verifications were performed, one new pole was placed near SMF 1 and five poles were removed.

The new alignment ran from the existing pole at the southeast corner of SMF 1, to one new pole near the southwest corner of the tent. From there, it fed over to the modified pole at the GWTS and then over the canal to the remaining pole at southeast corner of the northeast laydown area.

This work allowed the realignment of the 12-kV line away from the south end of the Discharge Canal, where extensive excavation work was performed. It also cleared poles from the northeast laydown area, so that abatement work could proceed and the final site grading contours could be established. This configuration was not the end state, as more work was required. This was a necessary interim measure.

2) Offices and Facilities Demolition

Multiple offices and service buildings were located around the site to support decommissioning. Many of these were temporary office complexes or single trailers. Others were pre-existing metal or concrete block buildings and served multiple purposes. Of approximately forty structures, the majority were mobile office trailers. These have been systematically removed as the project de-staffs.

Common to nearly every building removal were requirements to obtain the necessary permits; remove commodities, universal and electronic waste; identify any potential hazardous wastes and plan remediation; mark excavation areas and utilities; establish RP and FSS controls; erect barricades and signage for access control; erect debris curtains and fencing to protect adjacent work areas; place spill kits and eyewash stations in the work area; mobilize waste containers; de-energize and air gap electrical, water, air and other energy sources; implement BMPs; perform characterization sampling; perform biological clearance; and properly abandon nearly wells, standpipes, vaults and conduits.

3) Other Services/Letter of Credit

PG&E incurred costs for other services and captured those costs in a category called "Other Services." This category included work scope and services that were added to the CWC's contract.

Though originally written for waste support, the initial Contract Work Authorization was amended and specified providing the technically-qualified labor and equipment. PG&E determined it was more cost effective to allocate some of the self-perform work to the CWC for performance by CWC personnel, and to contracted groups with specific expertise, using their specialized equipment. PG&E recognized the need for these additional services not covered in the project's technical specifications. These services included asbestos abatement and trailer removal.

Asbestos abatement activities on the RFB roof and Building 5 included the removal of approximately 5,000 cubic feet of ACM roofing and the removal of Building 5's interior and exterior asbestos. Additional scope included erecting a Class II decontamination area, installing temporary power, installing a fall-protection guardrail barrier and establishing an asbestos-regulated area and rigging-exclusion zone.

Removal of PG&E-owned trailers that were not identified for demolition or removal from HBPP by the CW Contract were removed under Other Services. This included Trailers 9, 10A, 12-1, 12-2, 12-3, 12-4, 12-6, 12-7, 18, 22, 25 and 35. The CWC prepped these trailers for removal and/or demolition as requested, including: removal of furniture, equipment and appliances; cleaning; disconnecting services from them; and surveying them for release.

The Letter of Credit from the CWC was a guarantee of performance specifying that in the event of default, PG&E may present the letter to the issuing bank and draw the face amount set forth in the letter of credit. These costs are associated with the

CWC bank fees charged by the bank for the open liability on their resources.

4. Waste Disposal (Excludes Caisson/Canals)

a. Summary

The HBPP Unit 3 decommissioning and demolition CWP involved several work faces, which generated debris from nuclear plant demolition, Caisson removal and canal remediation. The debris was managed for offsite disposal or reused on site. The CWC developed a management program to manage wastes in accordance with PG&E's contract specifications, using PG&E's already-established Safety, Risk, Waste Reduction, Quality Control, Waste Management and Radiological Protection Programs. PG&E staff provided oversight to the CWC's Waste Management group to ensure CWC adherence to state and federal regulatory requirements and on-site waste management practices. The Waste Management group also provided direction in logistical areas, such as scheduling, WAC, waste accumulation, packaging, loading and shipping.

The performance goal for the CWP was to safely, efficiently and cost-effectively manage waste, while protecting or mitigating the effects to the environment. In addition to removal of waste, the performance goal included the disposition of equipment and tools (i.e., heavy equipment, IMs or waste containers and excess materials or supplies) and submittal of shipping and waste disposal documents to PG&E Document Control for retention as retrievable records.

Waste shipments are scheduled for off-site transport on an established schedule. During the CWP, the following shipments were made from HBPP for Civil Works (excluding Caisson/Canals):

2015	281 shipments	8.8 million pounds
2016	533 shipments	30.8 million pounds
2017	261 shipments	19.4 million pounds
2018	681 shipments	25.2 million pounds

Also included for reasonableness review are $5.5 million for costs incurred during 2012 through 2014.

b. Planning

During decommissioning planning, waste transport and disposal costs were anticipated to be a significant expense associated with the CWP. These costs were reflected in PG&E's preliminary estimates of waste generation used to establish the waste budget. Initial volumes of waste soils and debris during the start of the CWC's work in 2014, indicated higher-than-estimated volumes of waste requiring disposal. CWC and the Waste Management Team developed methods of waste reduction, utilizing early segregation of material by separating clean from contaminated material. These reduced materials requiring off-site disposal, while increasing materials allowed to be reused on site. These methods included early segregation of clean and contaminated waste streams and averaging the radionuclide concentration, to send a minimal amount of material with higher activity to Clive, Utah in order to avoid higher disposal costs. By utilizing multiple waste disposal facilities, HBPP was able to find the safest methods and realize the lowest costs for waste disposal for a given type or class of waste.

c. Waste Management Staffing

The CWC maintained a staff of waste management professionals known as the Waste Management group. Members of this group specialized in radioactive and hazardous waste management. Waste Management duties included preparing waste material for suitable load-out, waste handling, packaging of waste for disposal and preparation and certification of required shipping papers and notifications. These responsibilities spanned the requirements of state and federal hazardous waste management regulations. Additionally, this group interfaced with transportation and disposal vendors to ensure PG&E service needs were met and that vendors met PG&E Management expectations for safety by implementing various laws, regulations and requirements.

Waste Management staffing was structured to optimally support efficient packaging, handling and transportation of waste to disposal sites. The CWC provided physical labor and supervision to support Waste Management activities for the CWP. Staffing levels fluctuated commensurate with the volume of waste being handled and natural attrition of staff. Supervisory oversight occasionally identified the need for additional staff. For example, when the project selected 10 cubic yard bags for packaging some waste material, a resultant workflow analysis identified the need for additional staff members.

d. Work Processes

1) Waste Determination

Waste determination was the process where material type, origin and risk factors were evaluated to determine the disposition of materials for on-site reuse, asset recovery, or characterization for waste disposal. Each type of demolition debris was evaluated differently based on the type of material. The goal was to minimize the volume of material determined to be waste to the extent it could be performed safely and be compliant with state and federal regulations.

The soil waste evaluation was a multi-step process. For demolition debris that included concrete, rebar, structural steel, asphalt and grubbing, the evaluation process included criteria such as: eligibility for reuse based on origin of the material; radiological release criteria for the debris; and cost of processing.

2) Waste Acceptance Criteria

WAC established the minimum requirements for classes of waste destined for a radioactive waste disposal site. Requirements were intended to facilitate handling and provide protection of the health and safety of CWC and PG&E personnel and disposal facilities. Examples of criteria include requirements for packaging; liquid waste; flammable or explosive waste; volatile waste; pyrophoric materials; and hazardous, biological, pathogenic or infectious waste.

Stability requirements were intended to ensure waste did not structurally degrade and affect the overall stability of the disposal site through slumping, collapse, or other failure of the disposal unit, thereby leading to water infiltration. Stability was also a factor in limiting exposure to an inadvertent intruder, since it provides a recognizable and non-dispersible waste.

Waste was required to have structural stability. A structurally-stable waste form will generally maintain its physical dimensions and its form under expected disposal conditions such as: weight of overburden and compaction equipment; the presence of moisture and/or microbial activity; and internal factors, such as radiation effects and chemical changes. Structural stability can be provided by the waste form itself, processing the waste to a stable form, or placing the waste in a disposal container or structure that provides stability after disposal.

Liquid wastes, or wastes containing liquid, were required to be converted into a form that contained as little free-standing and noncorrosive liquid as is reasonably achievable. In no case could the liquid exceed 1 percent of the volume of the waste when the waste was in a disposal container designed to ensure stability, or 0.5 percent of the volume of the waste for waste processed to a stable form. In addition, void spaces within the waste and between the waste and its package had to be reduced to the extent practicable.

CWP Waste Management activities were oriented to ensure the WAC were met, thereby minimizing waste processing costs. Wastes not meeting the above criteria incurred additional costs with further processing on site, offsite processing at a processor for subsequent shipment to disposal, or processing by the waste disposal site.

3) Waste Packaging and Handling

Within the CWC's scope of work, the commodities, equipment, demolition debris and soil designated as waste were packaged and shipped to disposal facilities. The majority of the radiologically-impacted material was shipped to Grand View, Idaho (Grand View), Clive, Utah (Clive) and Andrews, Texas (Andrews). A portion of non-radioactive material that could not be reused was shipped to Beatty, Nevada (Beatty).

Two large tents, designated as SMF 1 and SMF 2, were constructed to manage bulk waste materials generated from the CWP. The SMFs allowed for wet soils, sediments and waste material to be dried out prior to loading containers. The SMFs allowed waste to be processed (stockpiled, crushed, conditioned, processed and packaged into containers for transport) throughout the year to meet transport schedules, regardless of inclement weather conditions. The advantage of using the SMFs was reduced costs associated with waste-handling operations.

Additional savings were realized with the use of stockpile locations, which provided a suitable location for risk-reducing processes such as rubblizing concrete. Rubblizing the waste provided greater stability once loaded and reduced the chance of damage to shipping containers. The Andrews disposal facility offered a reduced disposal cost for size-reduced concrete.

Most of waste generated from early nuclear facilities demolition was direct-loaded into Industrial Packaging (IP) IMs, thus avoiding the rehandling of materials. Waste soil was added to maximize efficiency for each shipment. As the rate of waste generation increased, Waste personnel determined that hauling waste into the SMFs for processing to meet acceptance criteria allowed demolition work to progress at an increased rate, with no impact on the CWP schedule. Most of waste generated was comprised of soil, concrete, steel and small amounts of other construction debris like metal, wood and plastics.

In 2016, HBPP shifted methods of loading and shipping waste materials from direct loading in the field, to using the SMF for staging and loading shipments. This change occurred in part due to acquiring a disposal agreement with a facility at Andrews, Texas. This waste facility had the ability to receive IP-1 waste bags via railcars, thus allowing HBPP to ship more material per shipment and at a reduced cost. This method of shipping allowed HBPP to replace the IMs with IP-1 bags for soil or crushed concrete.

5. Small Value Contracts

The Small Value Contracts category includes Small Dollar Vendors and Specialty Contracts, which fell outside major scopes of work. Small Dollar Vendors provided mostly generic services for office and facilities maintenance, while Specialty contractors generally performed functions unique to the decommissioning project.

Small Dollar Vendors include janitorial services, building maintenance services, portable toilet rental and maintenance, signage, furniture rental, office supplies, trash and refuse collection, communication services, moving and storage services, calibration services, document shredding, mobile facility rentals and badging equipment.

Specialty Contracts provide overall support to the project, addressing specific areas of the decommissioning process. These include specialty consultants who provide expertise on project management; local, state and federal regulation requirements; permitting; waste disposal; and equipment. This category also includes specialty printing, communication and internet technical services. Specialty contracts are used to provide monitoring equipment programs for RP, which supports ALARA requirements and provides overhead staffing to support the team in the field. Small value and specialty contracts are used for membership costs, NRC fees, Environmental Sampling Analysis, drilling and well installation, certified asbestos consultants, SWPPP support, industrial security services, subject matter expert support, emergency planning fees, onsite medical services, legal support and for vendors with scopes of work falling outside major project scopes.

Starting in 2015, Small Value Contracts were allocated between the base scope (Small Value Contracts) and Caisson, based upon the amount of work being performed.

During 2015 through 2018, actual costs in Small Value Contracts were $11.0 million, compared to a cost estimate of $13 million. In addition, $38 thousand in costs 2012 through 2014 is presented for reasonableness review.

6. Spent Fuel Management

a. Summary

The HBPP ISFSI operates under a separate and independent NRC license. The ISFSI will continue to operate following the termination of the HBPP operating license, until all spent fuel and GTCC material has been transferred from the ISFSI to the DOE. After transfer, the ISFSI will be decommissioned, and the ISFSI license terminated. Until that time, PG&E will continue to incur security and O&M costs associated with the ISFSI.

In the 2015 NDCTP, the CPUC accepted PG&E's proposal that due to the recurring and long-term nature of these costs, they be reviewed for reasonableness in each NDCTP, rather than waiting until final ISFSI site decommissioning. This section presents for review a total of $27.7 million for costs incurred during 2015-2018, compared to an approved cost estimate of $37.7 million. The underspend is due to a delay in the commencement of certain ISFSI improvements, below-budget staffing and a reduced need for Engineering/Specialty Contracts.

b. Staffing

ISFSI Security is responsible for the security of the safe and secure storage of 390 spent fuel assemblies in five casks and GTCC in one cask from the decommissioned HBPP. Security personnel are also responsible for security training, procedure writing, ISFSI licensing and access authorization. ISFSI staff's responsibilities include monitoring and maintaining the ISFSI facility. PG&E ISFSI specialists, who also function as Armed Security Officers (ASO), are trained and qualified in accordance with the Guard Training Plan and the ISFSI Final Safety Analysis Report. They conduct 24-hour surveillance of the spent fuel and comply with NRC security requirements. ISFSI specialists' duties include conducting patrols and searches and verification of authorized personnel and activities in the ISFSI. ISFSI Shift Managers are responsible for supervision of officers and shift activities and implementation of the site's emergency plan. In addition to their normal duties, they must qualify as ASOs and can revise nuclear quality and department-level procedures.

c. ISFSI Operations and Maintenance

ISFSI O&M functions include ongoing management, safety and compliance necessary to meet NRC requirements. Key contributing activities and elements of ISFSI O&M totals during the period 2015 through 2018, included overhead, procedure revision, communications enhancements for continued compliance with NRC standards, engineering services, guard booth enhancements, required improvements to the Vehicle Barrier System (VBS), and ISFSI Team training.

There was a delay to the expected date for upgrading the ISFSI security system to allow coordination with DCPP to standardize system operations. Additionally, a scheduling adjustment moved the HBPP training tracking system into the next triennial filing period as it transitioned to a Quality Database. Further decreasing current expenditures, a weapons simulation system was delayed until after the HBPP decommissioning cleared the needed space.

d. ISFSI Staffing/Engineering/Specialty Contracts

ISFSI staffing costs were those non-Security personnel assigned to support the O&M of the ISFSI. Engineering and specialty contracts costs supported discrete, well-defined missions at the ISFSI.

Specific work performed in this category includes communication system upgrades to maintain a level of communication that met NRC requirements; procedure specialists; technical briefing development consultant who also was responsible for responding to RFIs and assembling backup documentation for completed projects review and the decommissioning project report; CWC enlistment to provide Coastal Access Trail repairs and maintenance in accordance with requirements outlined in the CDP; electrical engineering firm support for troubleshooting of electrical and electronic equipment, developing work instructions for repair or installation, quality receipt inspections and post-modification testing; turnover of the ISFSI Engineering support to

Diablo Canyon Power Plant Engineering; the annual Independent Management Review; support of ISFSI engineering requirements, including relicensing assistance, ISP-511 inspection records and procedure rewriting, Alkali-Silica Reaction concrete evaluation, corrosive soils sampling plan development and execution, VBS design and maintenance support, annual ISFSI concrete inspection and other support activities requirements.

SMEs were contracted to support strengthening the ISFSI Team on regulatory requirements and implementing industry BMPs for quality-related items; an independent peer review and evaluation of the Access Authorization Program; and technical analyses to facilitate the license renewal of the ISFSI site-specific license Phase II with the NRC.

e. ISFSI Infrastructure Expenses

Specific infrastructure work is described below.

An ISFSI monitoring sump was previously abandoned during construction of the Portal Monitor Road. The 4-inch drain line from the sump needed a future access point, as well as drainage system evaluation and environmental soil sampling outside the ISFSI protected area. The on-site CWC did the civil work and a CWC environmental consultant performed the hand borings and soil analysis.

Site support was provided by the CWC performing decommissioning of HBPP, and included manpower, operators and equipment such as forklifts and cranes, when needed. This equipment was required for periodic maintenance troubleshooting of security systems; support from Electrical Engineering; utilization of forklifts for K-rail movement; moving and installation of storage containers; support during the ISFSI Relicensing Lid Lift Activities; movement of the VBS for refurbishment; removal and replacement of Building 11 AC unit; and removal of riprap on the slope to identify HB ISFSI drain pipe terminus, etc.

One of the existing consulting companies was engaged to prepare the ISFSI licensing renewal plan and participate in NRC and other industry activities. They also prepared and conducted a license renewal-lead inspection and finalized the inspection package as part of the submittal for the license renewal of the HB ISFSI site-specific license.

The provider of nuclear waste storage canisters (aka casks) was engaged to answer various inquiries from ISFSI Management, including relief device, rupture disks and torque values.

f. Nuclear Regulatory Commission Fees

For the 2015 through 2018 period, NRC Permits and Fees were $174 thousand.

The NRC is statutorily required by Congress to recover most of its budget authority through fees assessed to licensees. Most of these costs were for the triennial inspection of the site and the ensuing written reports, examining the "Assurance of Funding" letter, Emergency Plan review and Security Plan review, a records exemption request, reviewing the Decommissioning Funding Plan and Background Security L Clearance checks. These were performed in 2015 through 2017.

7. Caisson

a. Summary

Removal of the Caisson implemented a FOAK shoring and water cutoff wall using CSM technology. PG&E management and CWC management interfaced closely to evaluate several shoring and water cut-off designs and ultimately agreed upon a final design that adequately addressed safety concerns, risk and specific site challenges. The 2015 NDCTP approved budget for the Caisson Removal project is $151 million, and the project has been completed for $151 million. Completion of this unique project on time and on budget is an extraordinary achievement.

The scope for Caisson field work included designing shoring and the cut-off wall, pre-trenching, installing the shoring and cut-off wall, dewatering, excavating and removing the Caisson and backfilling. CWC costs included project overhead staffing and indirect costs, which could not be directly assigned to specific decommissioning activities. These costs included trailer rentals; van transportation, including rentals and fuel; Management travel; Caisson-specific training; incidental expenses; and subsistence.

b. Field Work

In the 2012 NDCTP, the CPUC approved PG&E's plan to remove the Caisson and associated estimated costs. In the 2015 NDCTP, the CPUC approved PG&E's revised estimate which was based on a methodology change for removal.

1) Planning

PG&E worked with industry experts to develop a conceptual design for Caisson removal and compile a cost estimate, utilizing the results of the 2012 Caisson Removal Feasibility Study. The conceptual approach included installation of a cement-bentonite water cutoff wall. The original CW contract endorsed this conceptual approach and PG&E directed the CWC to evaluate and implement the concept. The CWC's detailed analysis and evaluation found technical implementation issues with the conceptual design, which precluded its practical implementation at HBPP. Many alternative options were developed and analyzed. PG&E and the CWC worked together to agree on a final design, the CSM wall.

2) Evaluation of Alternate Caisson Removal Technologies

The CWC evaluated a number of alternative methodologies and technologies to accomplish the Caisson removal work scope Within the realm of regulatory mandates, PG&E was supportive of the CWC's attempts at innovation and optimization of work execution.

The CWC presented numerous options to the HBPP Management Team, studying and vetting alternate technologies and viable execution sequencing. The primary industry technologies and methods considered for use at HBPP were Slurry Wall, Soil Nail Wall, Freeze Wall, Sheet Pile, Ring Reinforcement and the CSM Wall. These alternate technologies are discussed in detail in Chapter 9, Attachment A, Section 9.1.2.

This time- and labor-intensive effort eventually paid off with a streamlined execution strategy, which contributed to maintaining the overall decommissioning schedule of the project previously filed. The end result was the optimal execution of the work scope and space, in many cases allowing concurrent work activities on multiple work fronts.

3) Slurry Wall Concept

During the slurry wall design phase, the slurry wall contractors continued to revise the planned installation approach. In the course of design development, the slurry wall contractor expressed concern that tight vertical tolerances could only be met with great effort, potentially affecting cost and schedule. The slurry wall contractor ultimately proposed a combined clamshell bucket and hydromill approach to install slurry wall panels and continued planning that approach.

The CWC was concerned that the perimeter slurry wall and the proposed deep shoring components were analyzed as separate components, rather than collectively as a system. These concerns were compounded after observing slurry wall operations at another project. The CWC expressed concerns regarding the slurry wall contractor's ability to control verticality and the technology's increased difficulty in addressing cross-contamination concerns and environmental SWPPP requirements at HBPP.

The CWC and PG&E reevaluated the design approach outlined in the original proposal and in the awarded CW contract. As the CWC further developed design plans, an option to complete the perimeter wall with CSM technology was developed. A specialty contractor described the CSM process as a modified trench-cutter technique, to be used for both perimeter groundwater cutoff and for Caisson demolition SOE.

4) CSM Wall Final Design

The HBPP project provided oversight to vet seismic criteria and design integration of the water cutoff wall with the deep shoring of the excavation cutoff wall system. Early in the design phase, Project Teams from HBPP and the primary contractor visited two sites to benchmark the project and to evaluate appropriate means and methods for similar work to be performed at HBPP. Appropriate independent oversight was implemented by HBPP through its SMEs.

HBPP made use of its SMEs, Engineering and Consultant staff to assess, evaluate and document positions on significant technical issues. This ensured alternatives were being addressed and any alternate approaches were appropriately evaluated.

During the development of the design, the HBPP Risk Analyst met with the Project Team to provide an overview of the PG&E risk comparison initiative, explaining its importance and specifics of the Caisson removal project.

The CWC petitioned HBPP Management for approval to change the original approach for water cutoff from oblong slurry wall technology to circular CSM wall technology. The CWC examined different water cutoff and shoring wall configurations and presented details to PG&E Management. After several vetting iterations, which involved input from PG&E Corporate SMEs and outside SMEs, HBPP agreed to the five-concentric-ring, circular, combined water cutoff and excavation shoring wall configuration.

The final design contained three key support elements: the perimeter cutoff wall, the dewatering well system and the Caisson deep shoring system. The CSM wall was a cylindrical cementitious structure encircling the Reactor Caisson to allow excavation in nearly dry conditions. The CSM wall was constructed by in-situ mixing of native soils, bentonite and cement in two hundred and fifty-five individual overlapping rectangular panels, forming five concentric rings. The CSM rings were installed to specific design depths, allowing for excavation to a depth of 96 feet.

The inside ring had a diameter of 110 feet and was centered near the Unit 3 reactor Caisson. This inner ring and three adjacent rings formed the SOE. A water cutoff wall keyed into the Unit F geological clay layer, formed a "contained" structure, allowing for removal of the groundwater inside the CSM wall via conventional dewatering wells.

As installed, the five rings comprised an overall wall thickness of approximately 13 feet throughout. The bottom of the reactor Caisson structure was approximately 80 feet BGS and the bottom of the inner shoring ring was approximately 106 feet below grade. Each successive shoring ring stair-stepped down in 4-foot increments, to a depth of 118 feet. The water cutoff ring was approximately 173 feet deep. Four 126-foot deep dewatering wells located inside the deep shoring system allowed for dewatering, providing for dry excavation of deep structures.

5) CSM Wall Installation Equipment

There was no existing fixed-mast CSM equipment capable of reaching the required depth of 170 feet necessary to key into the Unit F clay layer for water cutoff, while remaining within design vertical tolerance. The equipment manufacturer advised the CSM contractor that a BG-50 machine could be fabricated with an extended rigid Kelly Bar mast and shipped to meet the CWC's schedule requirements.

The lead time for design, production and shipping was approximately eight months, and the scheduled start date for the CSM wall was about eight and one-half months out, pressing a decision to procure the BG-50 to comply with the project's baseline completion schedule.

The proposed fixed-mast CSM hydromill had a clear advantage over a cable-hung hydromill in that the cutting heads were mounted to a rigid bar (mast) and could be hydraulically adjusted for verticality via computer control.

6) CSM CW Contract Specification

With the technology change from slurry wall to CSM wall, a technical specification was needed. The CWC developed the initial specification in collaboration with the CSM specialty contractor and

Designer of Record (DOR), based on similar CSM project specifications previously used in the construction of CSM projects throughout California. Elements of the slurry wall specification were adopted for the outermost ring of the CSM wall, considered the cutoff wall.

To maximize safety margins, HBPP requested a Safety Factor (SF) of 3 on the final wall strength in the CSM wall specification. The design also considered an evaluation of a hundred-year seismic event during the Caisson demolition and excavation. DOR calculations for hydrostatic forces outside the wall outlined the CSM compressive strength requirements for an SF of 3 per depth of excavation. Specifically, strength requirements increased from the upper elevations as the depth increased. Based on the assumption that the CSM panels were homogenous, the specification aligned with the strength required at the greatest depth of excavation.

The specification required that a minimum of 75 percent of individual cylinders tested for strength must meet or exceed the design strength. The specification allowed for 25 percent of the samples to be lower than the design strength, so long as the overall average met or exceeded 1,000 per square inch (psi). Strength testing was performed on wet grab samples taken of the mix during installation.

The initial specification also included criteria for panel verticality, panel overlap and alignment. PG&E consulted with several structural and seismic engineering SMEs for consensus on the predicted design strength of the CSM wall and the overall specification criteria. All parties agreed with the initial specification and the project moved forward with installation.

7) CSM Wall Installation

Pre-trenching was among the early field activities started. Pre-trenching and excavation were used to remove known shallow commodities and remediate any radiological contamination within the areas in the slurry wall or the CSM wall footprint.

Pre-trenching progressed as originally planned in support of a coffin-shaped slurry wall. Since the commodity removal associated with pre-trenching would be required regardless of the methods used for Caisson removal, overall project schedule time was preserved by targeting the slurry wall footprint for pre-trenching prior to finalizing the CSM wall design.

The Unit 2 slab area was the only area outside the RCA within the slurry wall footprint. After this area was pre-trenched to the RCA boundary, project focus shifted to working inside the RCA. This required meticulous planning and coordination to facilitate ongoing decommissioning preparation activities with minimal disruption, including major demolition and excavation work within the small, fenced-in RCA.

There were several distinct scopes of work ongoing within the RCA, including: reactor vessel segmentation; preparation of the RFB for OAD; asbestos abatement on the RFB outer walls; decommissioning of the LRWB; equipment and systems; geotechnical borings; and groundwater/storm water management. Each of these individual projects had multi-disciplined workforces who passed through Access Control on the east end of the RCA. The only logical available area within the RCA conducive to pre-trenching was the northwest corner of the RCA. Above-grade demolition and subgrade excavations began at this location Demolition of the SAS was required in order to complete pre-trenching.

Interference between the RFB and the circular CSM wall alignment required field work and schedule balance so work could be completed safely. As a result, in addition to the previously-completed pre-trenching activities, it was necessary to demolish and remove the east 40-foot section of the RFB to allow for pre-trenching, underground utility removal and FSS activities.

The CSM wall installation baseline milestone start date was June 2015 and the scheduled completion was April 2016. Multiple additional required support tasks, such as installation of a distribution power panel, additional Baker tanks, seismic restraints for cement and sand silos, pushed the actual start date to July 2015. The installation took about 12 months and ended in June 2016.

A batch plant was assembled and installed on the Unit 1 footprint at the west end of the fossil power block to support operation of the BG-40 fixed-mast hydromill. This batch plant had several 20,000-gallon capacity mobile tanks connected in series in order to efficiently recycle water and help meet the 30,000 gallons-per-day water demand. The plant also had two silos for cement storage and large hoppers for bentonite. After the second hydromill arrived on site, a second identical batch plant was installed. Operation of the batch plant required careful control, mixing and monitoring of raw materials to maintain the specified mix design. This required a steady delivery rotation of cement trucks contracted and supplied by local vendors during drilling operations.

A large de-sanding unit was also operated adjacent to the first batch plant. The de-sander separated sand from the slurry, which was then pumped back to the rig. It also reclaimed water from the wet excavation spoils, optimizing water consumption. Multiple dump trucks and loaders operated between the de-sander unit and CSM wall, clearing the installation site of wet excavation spoils. When the second hydromill machine was brought on site, an additional portable centrifugal de-sanding unit was added, as planned.

When CSM mobilization and pre-trenching complete was on the southwest area of the footprint, panel installation began. Panels were installed in a “leap-frog” type sequence. Within a ring, after installation of the first panel, the third panel in the pattern was installed and the middle panel within the pattern was installed last. This methodology was also applied for rings, with the innermost ring panels installed first, then the middle ring and/or outer ring, then lastly, the second and/or fourth ring.

8) Specific Challenges

The CSM panel installation sequence was frequently interrupted to facilitate other field work activities such as RFB demolition, which required relocating the CSM drilling equipment so that panel installation could continue in a different area without schedule interruption. Additionally, the CSM panel installation work was challenged by the presence of a demolition exclusion zone for personnel safety.

The CWC experienced construction challenges associated with large crane erection, electrical load center start-up, preparation of the BG-40 and BG-50 hydromill rig engineered working surfaces, and systemization and start-up of the bentonite/cement batch plant, all of which contributed to a one-month delay to the CSM installation start. The CWC and the CSM contractor were confident the delay could be recovered. Working longer days and on weekends focused on the schedule directly related to critical path activities.

Final wet grab sample test results at 56 days failed to meet the 75 percent criterion designated in the specification. The DOR evaluated the increasing strength requirements over the depth of the CSM wall. In October 2016, the technical specification was revised to move from absolute 1,000 psi average sample strength to a strength requirement by depth necessary to achieve a SF of 3. The specification retained the initial 75 percent/25 percent pass/fail criteria, allowing for deviation from this acceptance criteria with DOR approval.

The DOR and the CSM specialty contractor initiated a vertical core boring operation at their own expense to verify the compressive strength of the wall. The compressive strength test results of the vertical cores proved inconclusive, due to several issues encountered during core recovery. As a result, the DOR proposed a horizontal core boring operation from within the excavation as the Caisson demolition progressed. This allowed for shorter cores, which alleviated the guidance and recovery issues associated with the long vertical core sampling method. In addition, due to the horizontal core orientation, a larger sample size was obtained, with each sample containing representative samples from several individual panels. Horizontal drilling was performed at 10-foot depth intervals for the first 60 feet of the excavation. When a 60-foot depth was reached, the results of the program were assessed by the DOR to determine if additional SOE was needed. Based on the results of the program, the DOR determined that additional reinforcement was in fact needed to sustain the targeted SF of 3.

Based on test results and DOR evaluation, a 12-inch thick layer of 4,000 psi shotcrete, starting at the 50-foot depth and continuing to the bottom of the excavation, was installed. A joint approval among the DOR, CSM specialty contractor and HBPP was reached, which allowed the excavation to proceed past a depth of 50 feet with the shotcrete reinforcement.

The initial specification also had tight verticality and panel overlap criteria. Initially, panels had a 9-inch maximum allowable circumferential vertical deviation. A 3-dimentional engineering model comprised of actual installation data for the water cut-off wall, was reviewed by the DOR, the CWC and the CSM specialty contractor. They jointly determined that overlap was not necessary to meet design intent, so long as no apparent void existed between panels.

The revised specification amended the 9-inch circumferential deviation criteria for all panels to a maximum 12-inch allowable deviation. Additionally, the initial specification required a minimum 12-inch overlap between panels. Two-dimensional engineering models comprised of actual installation data for panel overlap were reviewed after installation of each panel. The DOR reviewed and approved all cases of panel verticality and overlap that did not meet the revised specification.

Verticality and overlaps meeting the design intent for the water cutoff wall were confirmed with the successful groundwater drawdown test inside the CSM wall.

9) Dewatering

A dewatering system was installed within the boundary of the CSM wall, which incorporated geotechnical instrumentation placed in individual wells to monitor groundwater level and soil movement.

The water was managed mainly for groundwater within the structure and served a secondary function for storm water and dust control process water.

The system included four dewatering wells and four piezometer wells that were located inside the CSM wall and required careful observation during the excavation process to prevent damage by excavation equipment.

After demolition of the RFB and the commencement of Caisson demolition, the excavation groundwater levels were maintained based on current excavation level. As excavation began, the level was maintained at least 10 feet below the current excavation level. Three of the wells were active and one was maintained as a backup. Pumping rates were established and the pumps were run for 3 minutes at a time, in 13-minute intervals. The system's four pump discharge pipes connected to a header that emptied into a series of holding tanks, which then pumped directly to the GWTS, utilizing a control valve configuration and operating process.

Tracking the daily operation of the system included contingencies for rain events and seismic activity, etc. Four geotechnical inclinometers located around the perimeter of the CSM wall monitored below-ground lateral movements of the soil mass and CSM wall. They functioned as designed. No surprises or anomalies were detected during the Caisson removal.

10) Caisson Removal

The Caisson was a reinforced-concrete, below-grade structure, which served to house the reactor vessel and supporting operational equipment. This structure served to keep the high-water table at bay, as well as to provide a below-grade shell to house Unit 3's support systems and equipment, while retaining the surrounding soils in place. The upper portion of the Caisson was a rectangular structure, 50 feet wide (N-S) by 52 feet deep (E-W), and it extended from El. -14 to El. +12. The lower 58.5 feet of the Caisson was a heavily-reinforced 60-foot diameter, circular concrete structure with 4-foot-thick walls.

Caisson demolition and backfill included the removal of the Unit 3 deep foundation Caisson structure and its underlying tremie pad including concrete slabs, subgrade structures, embedded piping, soils, piling and debris. Caisson demolition work also included the operation of a dewatering system; the monitoring of geotechnical instrumentation systems; installation of a surface railing safety system and barrier system at working surface to protect workers; installation of a personnel access system; and installation of an excavation ventilation system. This work was completed during 2015-2018 with actual costs of $68.3 million.

Due to potential risk of contamination during Caisson removal, an impermeable layer was installed around the CSM. Its construction included the placement of controlled low-strength material, aggregate, storm water collection basins and utility conduits to supply temporary utilities during Caisson excavation. A rubber liner was installed to cover the completed CLSM foundation and create a waterproof barrier. The final working surface was finished with a gravel base to ensure proper water drainage into the storm water collection basins.

A scaffold stair tower was designed and installed incrementally within the CSM wall. The stair tower was supported by cantilevered steel beams, which were counterweighted with concrete barrier rails. They were braced to the existing shoring wall to support seismic loading requirements. As the excavation progressed, additional sections were added in 20-foot increments to provide safe access to and egress from the excavation.

Additional CSM shoring strength was provided by dowels, Welded Wire Fabric (WWF) and shotcrete. A layer of WWF and 6 inches of shotcrete were installed on the first 20 feet of the shaft to meet seismic and surcharge demands. An additional 10 feet of WWF, along with two rows of rock bolts, were installed below the shotcrete to mitigate spalling. No shotcrete lining was installed from El. -20 feet to El. -44 feet as this section of CSM wall met all strength requirements. WWF and 12 inches of shotcrete lining were installed at a depth of 51 feet and below.

Soil was excavated 6 feet at a time and the shotcrete liner was installed in 6-foot lifts. Once the Reactor Caisson's concrete was demolished and the shotcrete liner met required compressive strength specifications, the excavation progressed.

Caisson demolition and excavation was broken into three phases. Each phase was completed with the use of hydraulic excavators equipped with large concrete breakers, metal-cutting shears, and concrete processors. During the first phase, the upper portion of the Caisson, including the RFB slab from El. +12 to El. -20, as well as the exterior Caisson walls in the El. -20 to El. -30, were removed and the area excavated.

The second phase involved removing and segregating the Activated Region of the drywell (which was the interior ring of the Caisson) from the remaining portions of the structure below El. -30. The Activated Regions of the drywell were within El. -20 to El. -30.

The third and final phase was to remove the remainder of the Caisson and the adjacent soils, which extended from an El. of -30 to approximately El. -84.

Excavation began from El. +9.5 and proceeded in approximately 4-foot lifts. First, soils between the concrete structure and the CSM wall were removed from around the exterior of the Caisson. Following removal of the soils, the concrete structure was demolished down to the current soil elevation. This process was repeated until the entire structure, as well as the surrounding soils, were removed. The debris generated from these activities was used to fill void spaces within the structure, which provided additional working surface for demolition equipment. Excavated soil spoils to be utilized for reuse were processed through the GARDIAN system and then stockpiled at predetermined locations on site, to be used for the Caisson backfill process.

The initial phase of Caisson demolition activities was performed with the excavation equipment setup around the top of the CSM wall and the former SFP. The SFP had previously been backfilled with demolition debris generated during the RFB demolition. More working space within the CSM ring became available as the excavation progressed. This allowed for a makeshift ramp made up of debris, to be used on the east side of the excavation for the remaining demolition equipment to enter the hole during the first 20 feet of excavation. Alternately, excavation equipment was rigged and lowered into the excavation, utilizing a 275-ton support crane. The stair tower, its support beams and first tier of the scaffolding were installed once the excavation reached approximately 5 feet in depth.

Excavation and demolition continued in lifts down to El. -20. All soils and portions of the structure were fully removed down to this elevation. After the El. -20, the demolition process changed slightly to address issues specific to the Activated Region area. The change meant that the removal of the structure was restricted to excavation of soils and the demolition of structure, exempting the interior drywell concrete, interior suppression chamber liner plate and the drywell liner. This restriction was in effect until approximately El. -30 was reached. Following demolition of the exterior structure within this 10-foot elevation range, a 10-foot tall section of the drywell remained, which protruded above the working surface.

At this point, the top layer of soil was utilized as a sacrificial layer at the working surface. This sacrificial layer was used as a barrier layer to prevent Activated Region debris from comingling with the surrounding materials. Demolition of the Activated Region commenced as follows.

First, the suppression chamber liner plate was stripped from the drywell concrete (concrete and interior drywell liner plate remained in place). The liner was direct-loaded into IM for disposal following removal.

Next, the activated concrete from the drywell was demolished and direct-loaded into IMs for disposal. During concrete removal, the interior drywell liner plate served to prevent any Activated Region debris from falling into the drywell cavity. Following the completion of the activated concrete removal and load-out, the drywell liner plate was removed and direct-loaded for disposal.

At completion of the drywell liner plate removal, surveys were taken and the sacrificial material layer was disposed of, along with approximately 6 inches of soil and debris below the barrier layer.

Upon completion of the Activated Region removal, the remaining 55 feet of the Caisson and surrounding soils were removed in a manner similar to the first 32 feet of the excavation. This continued until the entirety of the structure was fully removed, as well as the base tremie concrete layer. Excavation equipment was removed and an FSS was completed per NRC direction. A third-party NRC consultant was present to observe and confirm that results of the survey met NRC acceptance criteria. Support equipment used for excavation and demolition work was removed from the hole, including dewatering wells, piezometer survey equipment, stair tower and the ventilation ducts and system. The inclinometers located outside the CSM wall were also removed.

11) Backfill

After the FSS was completed, the CWC backfilled the Caisson using stockpiled materials that had passed all survey criteria. A telestacker (conveyor belt system) was used to transport reuse materials that had been stockpiled at the Discharge Canal into the Caisson. The reuse materials were pushed with a caterpillar to an excavator, that loaded the conveyor system that deposited the materials into the Caisson excavation. Once this stockpile of materials was exhausted, dump trucks were used to continue the filling process of the Caisson excavation to approximately 20 feet below the top. This material was leveled with long-reach excavators, then crushed reuse concrete from the site was placed on top. A clay layer was placed over the crushed concrete, at approximately 10 feet below the top of the Caisson excavation. Geo-Tec fabric was placed over the clay and the remaining 10 feet were compacted. Compaction started with 12-inch lifts, finishing the top 3 feet in 8-inch lifts, until final compaction was met.

The clay layer and Geo-Tec fabric formed a protective pH barrier to prevent the concrete from affecting the existing water table. By utilizing multiple backfill methods (i.e., telestacker, long-reach excavators, caterpillar and compaction equipment), the CWC performed the scope of work ahead of the original forecast.

Demobilization from the Caisson backfill included cleaning, surveying and removing all the equipment used for the backfill process. It required that the impermeable layer installed to protect areas already in the FSS be removed; the capping off of any sampling wells in the area that could not be done earlier, based on critical path activities; and the FSS of the remaining HMS excavation that was not completed earlier in the project.

c. Project Staffing

Starting in 2015, staffing costs were split between the base scope (General Staffing) and Caisson, based upon the amount of work being performed. Caisson Removal Project Staffing actual costs during 2015-2018 total $13.2 million.

d. Waste Disposal

The upper portions of the RFB were removed prior to excavating the Caisson. Some concrete debris was used within the Caisson and suppression chamber to provide a safe and stable working base for heavy equipment.

The CWC was tasked to reuse soil from the Caisson excavation as much as possible on site. The waste volume forecast was based on the assumption that 75 percent of the soil from the Caisson excavation could be screened for reuse on site and only 25 percent of the volume would be classified as waste. Contrary to the original 75 percent reuse estimate, initially 0 percent of the soil was reused. The CWC ultimately developed better methods and processes for protecting the reuse soil and minimizing cross-contamination, thereby increasing the volume of reuse soil. The improved CWC methods, including removal of a sacrificial soil layer, control of material and focused remediation, resulted in an aggregate soil reuse volume of 65 percent.

The EL. +12 to EL. +2 concrete and soil were dispositioned as radwaste, due to contamination. Soil below the EL. +2 was expected to be clean or less contaminated and the Waste Management group reused as much of this soil as possible. Initially, the CWC extracted soil from the area between the Caisson and the CSM wall in 4-foot lifts. Radiologically-impacted concrete and steel and the top 1-foot layer of surrounding soil mixed with concrete debris were removed as waste. The remaining 3 feet of soil were removed and analyzed for reuse on site. However, due to concrete debris from the excavation and comingled material, the soil between the EL. +2 and EL. -6 could not be saved for reuse. Removal techniques and operations improved each lift, resulting in an increased percentage of soil preserved for reuse. As the CWC progressed in Caisson demolition, work performance improved and by mid-June 2017, the CWC had transitioned into 6-foot lifts to maximize the amount of reusable soil.

Concrete and soil waste materials were taken to the SMF for preparation and packaging. Materials were crushed and sized to adhere to waste disposal facilities' disposal incentives. Once crushed, the waste material was loaded into IP-1 bags destined to go to Andrews. Other materials were loaded into IP-1 IMs for shipment to Grand View.

A small portion of the structural steel in the Caisson had elevated levels of radiation and was also sent to Clive. Metal waste (piping, structural steel and rebar) was direct-loaded into IMs and sent to Grand View, Andrews and Clive, based on radiological conditions established during the waste categorization process.

Waste shipments are scheduled for off-site transport on an established schedule. During the period 2015 through 2018, the following shipments were made from HBPP for Caisson:

2015	509 shipments	19.5 million pounds
2016	91 shipments	4.6 million pounds
2017	490 shipments	60.3 million pounds
2018	102 shipments	10.0 million pounds

The projected expenditure was based upon the assumption that 75 percent of the soil from the Caisson excavation could be screened for reuse onsite.

e. License Termination Survey

Specific duties pertaining to Caisson decommissioning and remediation activities at HBPP included ensuring that turnover surveys were completed; soils and groundwater DCGLs for FSS were complied with; surveys were documented; procedures and programs were revised; NRC oversight was coordinated; and reports to the NRC and State of California regulators were produced properly.

The organization was managed by the Site Closure Manager. A lead Project Planner working for this group developed the license termination plan (LTP), which provided the plan for the site to be radiologically cleared and released for unrestricted use. The LTP application was submitted to the NRC as an amendment to the Facility Operating License for HBPP Unit 3. It provided detailed site characterization; descriptions of remaining dismantlement activities; plans for site remediation; technical data for development of site-specific DCGL; methods for FSS of excavated soils for reuse; detailed plans for the final radiological survey; description of the end state of the site; updated site-specific estimations of the remaining decommissioning costs; and an update to the site environmental report. Based on experience gained from other decommissioned sites, submittal of this plan as early as practical facilitated early end-state decisions and provided increased opportunities for stakeholder involvement.

The LTP was submitted to the NRC in May 2013 and ultimately approved by the NRC in May 2015. It was added to the Defueled Safety Analysis Report in November 2016. Its required bi-annual review occurred in February 2018, resulting in Revision 2 of the LTP.

Because of the similarity between MARSSIM and MARSAME, the FSS group prepared packages and performed surveys to disposition various materials and equipment that were or were not released from the site. Much of this type of work was performed during the demolition of the fossil-fueled units on the HBPP site. However, during Unit 3 decommissioning, there were times when it was beneficial to use the MARSAME process to plan and document surveys. These instances were for specific disposition of items, such as office trailers, major pieces of equipment and building debris. Like MARSSIM surveys, MARSAME surveys are quality records subject to NRC oversight.

NRC Oversight of the FSS Process

FSS staff coordinated with the NRC during decommissioning, with the NRC providing independent review of the process. Conference calls occurred on a regular basis and periodic meetings took place to update the NRC on Caisson decommissioning progress and anticipated FSS survey work. The NRC contractor was at times present on site, as requested by the NRC, to monitor FSS activities and perform independent measurements of areas being surveyed.

Survey Unit Documentation and License Termination

When all survey units within a given larger survey area were completed, relevant documentation was compiled into a submission report to the NRC for review and approval. As a visual aid for the review, site mapping and geospatial representations were overlaid, with sample data to be included in the final area report. A quality check process was used to validate the entire area report prior to its submittal to the NRC. Technical FSS staff answered requests for additional information during the NRC review.

A few survey area reports have been submitted for approval to the NRC, to support termination of the 10 CFR §50 License. A final report will be developed once most, or all area reports have been submitted to the NRC. Requests for additional information are being addressed during the review of any final survey area packages submitted.

Implementation of this process required key staffing positions such as an FSS Consulting Engineer, FSS Engineer, FSS Report Writer, Operations Foreman, Radiological Control Technician/FSS Technician and Radiological Decontamination Technician/FSS Labor Count Room. The RP organization was originally assigned the responsibility of analyzing radiological samples taken in the field. That responsibility was shifted to the Site Closure organization after major radiological source terms were removed and the main concern became measuring the environmental background levels. The Count Room functional area was responsible for analyzing radiological constituents of work area and environmental samples; calibrating and maintaining instrumentation; evaluating post-decommissioning status relative to DCGL; revising procedures and programs; assisting FSS with ISOCS surveys; and generating reports to the NRC and State of California regulators.

Final Status Survey Staffing

The FSS was staffed by experienced site termination professionals and technicians. Within the group were individuals with experience from SONGS Unit 1, Yankee Rowe, Fermi 1, Maine Yankee, Connecticut Yankee and various DOE and research reactor and facility decommissioning. In addition to the personnel with experience from other projects, locally-hired personnel, trained and qualified by the RP group, transferred to FSS roles to augment the experienced core group of technicians.

Final Status Survey Consulting Engineer

The FSS Consulting Engineer advised the FSS Supervisor on technical matters regarding the development and operation of the FSS Program. This position was responsible for developing and maintaining procedures, processes, technical basis, license basis and license termination plans and documents. The FSS Consulting Engineer advised Management and staff on how to complete assigned tasks, in addition to providing guidance on how to interact with stakeholders and regulatory agencies.

Final Status Survey Engineer

The FSS Engineer planned and developed survey packages and supporting documentation (i.e., technical position papers, procedures, work instructions and calculations). This position was responsible for developing and maintaining procedures, processes and plans for executing MARSSIM-compliant implementation strategies to support effective FSS. This included the compilations of data and reports.

Final Status Survey Report Writer

The FSS Report Writer prepared and packaged the FSS-related documentation and data required to support license termination. The FSS Report Writer assisted the FSS Engineer(s) and FSS Consulting Engineer in the preparation of survey packages and other FSS program documentation, including regulatory submittals, LTP and Data Quality Analysis reports.

Final Status Survey Foreman

The FSS Foreman provided guidance to FSS Technicians. The FSS Foreman provided radiological safety input for planning activities at the site and conferred with cross-departmental Supervision and Management to ensure support of scheduled activities.

Final Status Survey Technician

The FSS Technician ensured the project was successfully completed, while maintaining safety as the first priority. Personnel assigned to this position performed radiological surveys and provided that data to FSS Engineers, who would utilize the data to demonstrate the final site clearance criteria was met.

Since the FSS and RP functions were combined, these same Technicians also performed surveys for radiological release of equipment for offsite release, either utilizing a MARSAME survey package or RP procedures where no MARSAME package was deemed necessary.

The actual costs for this scope during 2015-2018 were $5.4 million.

f. Tools and Equipment

Starting in 2015, Tools & Equipment costs were split between the base scope (Remainder of Plant Systems) and Caisson.

g. Other

Costs in this category include Caisson RP Discrete (direct labor), Caisson Specialty Contracts, and Caisson Small Dollar Vendors.

Caisson Excavation RP Discrete

The Caisson's surfaces and accessible embedded piping were either decontaminated or removed in preparation for excavation. However, there were areas where the residual contamination could not be removed safely or cost effectively in advance of Caisson removal. RP monitoring, measuring and control were required during Caisson excavation and removal. Areas of concern which required RP Technician support included embedded pipe commodities, drywell-activated core region, suppression chamber removal and the removal of bulk plate steel and beams.

The RP and Environmental teams took confirmation samples upon completion of removal of contaminated material. During OAD, all tools and equipment had to be surveyed for radiological contamination at the end of each shift, prior to removal from the area and after any suspected contamination.

8. Canals

The Intake and Discharge Canal Remediation scope of work included mechanical removal of radiologically- and chemically-contaminated sediment from the Intake and Discharge Canals, demolition of the discharge outfall and levee to Humboldt Bay, demolition of the Intake and Discharge Canal headwork structures, restoration of the levee and Coastal Access Trail along the bay, management, dewatering of contaminated sediments and treatment of water to meet discharge permit requirements and disposal of canals waste.

The 2015 NDCTP approved estimate for the scope was $55.3 million. Total costs were $47 million.

a. Canal Removal

Remediation of the Intake and Discharge Canals required specific actions, including surveying, water management (water removal and treatment), shoring, asbestos abatement, demolition (Intake and Discharge structures and Discharge Canal outlet), sediment excavation and levee restoration. The end state of this scope of work was removal of clean and contaminated sediment accumulation for both canals and restoration of the levee to separate the Discharge Canal from Humboldt Bay.

1) Discharge Canal

The Discharge Canal was located on the northern portion of the HBPP property. The Discharge Canal was originally 360 feet long by 20 feet wide, with the bottom at a depth of approximately 7 feet below El. 0 Mean Lower Low Water (MLLW). The embankment height was 12 feet above the MLLW, with the side walls lined with riprap at a slope of 1.5:1. It was surrounded by higher-elevation industrial lands to the west and a temporary construction laydown facility to the east. There were four 48-inch diameter, unscreened outfall pipes connecting the Discharge Canal to Humboldt Bay.

During plant operation, the Discharge Canal was the final ponding location for cooling water from operating units before it entered Humboldt Bay. It was used to allow the temperature of water to normalize and for the settling of potential sediments and contaminants. In addition to sea water, effluent discharges entering the canal included the radwaste discharge and laundry discharge lines, fossil unit settling ponds, storm water, oily water separator and low-volume waste water, consisting of evaporator blow-down water. The chemical contaminants in the effluents included heavy metals and polycyclic aromatic hydrocarbons. Discharge effluents would go directly to the canal. Low-volume waste (oily water separator overflows) and boiler blow-down containing heavy metals were discharged through the settling ponds and a filtration system. Normal releases to the canal allowed some waste compounds to contact the material on the bottom and be retained by the clay particles. Each of these allowed effluents was included as a part of the operating discharge permits for the HBPP site.

Initial characterization of the sediment in the Discharge Canal in 1998 resulted in several samples with elevated Cs-137 concentrations and activity at depths up to 2 feet in the sediment. After initial characterization, permitted radioactive discharges from the LRW system continued. This was anticipated to result in a potential increase to the sampled activity in the sediment and silting layer. After termination of the flushing cooling water flows from Units 1 and 2, the sediment layer thickened significantly with sand and silt material. The accumulated sediments included naturally occurring materials carried on the ebbing and flowing tides mixed with radioactive chemical contaminants, which had been discharged, a portion of which settled in the canal sediments.

The CWC initiated preparatory work in June 2014. To prepare the Discharge Canal for remediation activities, temporary roads were built. A temporary laydown area measuring approximately 300 feet by 120 feet was prepared and paved. Temporary power was installed at the temporary laydown area to support the Pre-Treatment System (PTS) and dewatering operations. The PTS was installed south of the current GWTS, located in the area formerly known as Trailer City. The CWC completed the preparatory work in August 2014.

Discharge Canal field work commenced August 2014. The Discharge Canal was isolated from Humboldt Bay tidal waters to remediate the soil and remove asbestos-coated pipes that provided a connection between the Discharge Canal and the bay. Isolation was achieved by installing a sheet-pile coffer dam in the bay just outside the canal discharge pipes, to isolate the discharge pipes and the Discharge Canal from the bay. Once the coffer dam was installed, fish were removed from the canal by Biologists and then the canal was dewatered using electric- and diesel-powered dewatering pumps for transferring water.

Dewatering processes proceeded as planned, until December 7, 2014, when a storm pounded the sheet pile wall. Waves from the storm resulted in seawater in-leakage into the canal. In-leakage came from over the top of sheet pile and around the sides. In spite of utilizing conventional sheet pile design, the continual wave action produced constant flexing of the sheet pile walls, which created several large leaks in the wall.

In-leakage through the coffer dam exceeded the capacity of the GWTS, making the remediation of the interior of the Discharge Canal challenging. The CWC prepared a multi-part plan to reduce water in-leakage by plugging the Discharge Canal pipes with inflatable bladders, placing large cement blocks in front of the plugged pipes, and pouring a cement slurry between the pipes and the cement blocks to adequately seal the area and prevent water in-leakage. Divers prepared the inside of the pipes underwater by removing debris to prevent damage to the bladders. They then installed the bladders in the discharge piping. This action isolated the area inside the leaking coffer dam so water could be pumped back into the bay and allowed work to start inside the Discharge Canal.

The riprap above the normal water table was assumed radiologically clean and was stockpiled for reuse. Riprap from the water line down to bottom of the canal slope was removed using excavators, lifting the rocks individually from the embankment and placing them directly into dump trucks. All riprap from the Discharge Canal successfully passed through the GARDIAN system, was considered clean and was stockpiled for reuse at some stage in the process of the canal backfill operation or reconstruction of the levee and Coastal Access Trail.

The removal of years of sediment accumulation was performed next. The north half of the canal had the most accumulated sediment, being up to 3 feet in depth at some points. This accumulated sediment accounted for approximately 122,000 cubic feet of the 160,000 cubic feet removed from the entire canal. In addition to the sediment removal, the specification mandated excavation of up to 3 feet of the original clay liner placed in the Canal to minimize groundwater and contain the cooling water. Characterization demonstrated that Cs-137 and chemical contamination did not migrate into the lower levels of the clay liner at the bottom of the Discharge Canal. To be conservative, the top

6 inches of clay was removed as assurance that all contamination was addressed.

During excavation, groundwater upwelled in several locations through the exposed clay liner. Even with minimal clay liner removal, several springs in the south end were exposed, causing substantial in-leakage. In addition, during high tides seawater seeped through the soils of the canal at the north end, requiring additional management efforts by crews. All this in-leakage was treated in the GWTS.

In order to prevent potential spread of contamination in unexcavated material from groundwater intrusion from the exposed springs into the already excavated and surveyed area, a bladder dam was installed near the south end of the Discharge Canal. Once the decision to install a CSM wall in lieu of the slurry wall was made, the north end of the canal was filled with CSM spoils. An earthen berm created from CSM spoils was then built against the bladder dam and then built to a higher elevation than the bladder dam as a water intrusion barrier. This new soil accumulation served as a replacement dam allowing the bladder dam to be removed. The removal of sediment and topographic surveys was performed in stages, going from north end to the south, followed by FSS and confirmatory chemical sampling.

In order to remove the south headworks structure, riprap and storm drain discharge lines had to be removed, and remaining exposed ends were capped.

The south Discharge area canal south headworks removal was a high-risk, difficult work area. In order to remove this concrete monolith, the excavation required a 20-foot deep excavation area. The excavation area was further complicated, due to the presence of a nearby slope of approximately 85 degrees. Removal of an office trailer, handicap parking and some of the road above was performed, resulting in a reduction to an acceptable slope.

An excavator at the bottom of the canal removed material and placed it in a staging location prior to the material being loaded into trucks. A second excavator and dump trucks were staged at the top of the slope to receive the rubble. Personnel access paths, ladders and barricades were placed and maintained as needed.

Sumps were installed to address the water flow from the excavated springs to maintain water levels below the work surface during excavation and backfill. Water in-leakage was processed through the PTS and the GWTS.

The exposed south headworks were removed as far as possible without additional shoring requirements. The rubble was examined by RP and was disposed. The riprap was passed through the GARDIAN for eventual reuse or disposal. A second clay radwaste discharge line and two storm drain lines were cut and removed at the remaining slope and disposed of at the direction of RP and Environmental. After plugging the ends, surveyors marked the location of daylight pipe ends and left them for future removal with circulating water lines.

Upon completion of the sediment removal in the Discharge Canal, the CWC was able to address the remaining work of removing the ACM-covered discharge pipes. The tops of these pipes were 3 feet below sea level and with the original sheet pile wall continuing to have substantial leakage, these pipes remained underwater. The specialty contractor could not remove the piping underwater because of the potential for uncontrolled spread of ACM particles.

A safe work area needed to be established for the crew performing the abatement behind the sheet pile coffer dam. To reduce the flexing of the sheet pile, additional structural support was needed. To accomplish this, a water system was designed and installed. Next, water in-leakage issues needed to be addressed to ensure a dry work environment. In order to block in-leakage of sea water, a plastic-wrapped poured-in-place concrete plug was used to seal the wall, as well as isolate the concrete from pH influences on the bay. A temporary fence was installed, redirecting the Coastal

Access Trail around the worksite, thereby keeping the trail open to the public during this excavation.

Removal of the north headwall, pipes, the temporary trail; temporary facilities, including laydown area and crane pad; and addition of approximately 3 feet of fill below the pipes was performed. All materials were removed and the sheet pile wall was pulled in time to meet the fish window deadline of October 15 set by the CDFW.

2) Intake Canal

The Intake Canal led from King Salmon Road to the intake structure and was 550 feet long by 60 feet wide. The Intake Canal channeled ocean water from the bay via Fisherman's Channel, as a cooling water source for the original fossil power generation units and Unit 3.

Intake Canal remediation included removal of the concrete Intake infrastructure at the east end of the Intake Canal, which housed debris bar racks, a screen wash system, isolation gates and cooling water pumps. Some of these components were removed during fossil decommissioning or, in the case of Unit 3, when the unit was placed in SAFSTOR.

The first activity for the Intake Canal area was to install a water cutoff structure. Because a bladder dam would isolate more bank area than was available for remediation, an industry-standard sheet pile wall was installed instead by a specialty contractor. Just after the installation of the sheet pile wall, a fish relocation process was performed by one of the CWC specialty subcontractors. This process involved seining the area three times and installing a turbidity curtain upstream after seining was complete. Various marine life species were expected, found and appropriately released by the biologists.

Large-capacity water pumps outfitted with special screens to prevent the loss of marine wildlife were used to dewater the canal and pump water into the bay.

To meet the release criteria, Unit 1 Intake structure was cleaned out by the CWC and surveyed by HBPP FSS Technicians. The physical removal of the biological growths was required prior to surveying. Access was difficult because the structure was ~20 feet in height/depth, and primary access was from the bottom of the structure. Specialized scaffolding was erected, using long-handled tools and other various techniques, to allow crews safe access to the walls to execute cleaning of the structure. Survey results indicating the structure was free of radiological contamination were presented to the NRC and it was approved for free release, with the NRC granting HBPP permission to leave portions of the structure in the ground. This approved approach allowed the CWC to leave roughly 60 percent of the structure in place, resulting in a shortening of the schedule for the project. Removal of the fill rock used in the Intake structure during fossil decommissioning took longer than planned, because of 3-inch to 4-inch sized stone.

The Intake Canal contaminated soil was removed with a long-reach excavator and transferred to the Waste Department for disposal. Upon completion of the contaminated sediment removal, the HBPP FSS group performed FSS of the entire canal. During the FSS survey the HBPP Environmental group completed a chemical contamination survey, which allowed for a clean, free-released area for both radiological and chemical contamination.

The CCC canal remediation permit required restoration of the canal area. This restoration included the creation of new wetland areas that were an off-set for the filling in of the Discharge Canal. This new wetland created roughly 1.5 acres of new saltwater wetlands, which were vegetated per the permits with native species identified.

Creation of additional wetland areas expanded into the former Contractor Parking Lot. Creation of the wetland involved the removal of approximately 6,000 square yards of material. Work crews excavated the area to the grades established by the approved work plans, which were based on the site restoration permits. A portion of the material from the excavated area was used to backfill the remaining Intake structure to meet end-state final grades. The remaining material was transported to the Discharge Canal area, which was the main on-site staging area for reuse soil.

Upon completion of the excavation activities, the canal was reflooded. This was achieved by slowly removing sections of the sheet pile wall. This allowed the bay water to slowly reflood the dry canal area and prevented excessive erosion of the newly-excavated and profiled area.

The project was restricted to working within a fish window established by site restoration permits which limited in-water work to a less than a six-month window, from June to October. The project work began in June 2016 and was completed in December 2016. Special permission was received from the permitting agencies to work past the original fish window date of October 2016. This was granted because of the limited amount of impact the remaining work activities would have on the neighboring water habitat areas.

b. Canal Disposal

Although the Discharge Canal sediment was previously thought to have much higher levels of contamination, upon excavation it was characterized well within the acceptance criteria for exempt waste. Based on measured and surveyed contamination levels in the excavated materials, no Class A waste shipments to an appropriate disposal site were included in the shipping forecast. In addition, the waste volume excavated was less than expected, because the Cs-137 and chemical contamination did not migrate into the lower levels of the sediment or the clay layer at the bottom of the Discharge Canal. The original waste volume estimate was based on a contaminated clay layer of 3 feet along the bottom of the Discharge Canal.

Instead of the original basis of 30,970 pounds, the actual weight of loaded IMs was approximately 32,000 pounds to 35,000 pounds. This optimized the IM weight, which further reduced the number of IM shipments. The reduced waste volume, along with the waste shipments being classified as exempt materials for appropriate site disposal, resulted in a cost avoidance.

Originally, the entire Intake structure, which was comprised of reinforced concrete, was planned for removal. However, only the top 3 feet of the structure needed to be removed leaving roughly 60 percent of the structure in place. After the canal was dewatered and the contaminated soils removed, the Remediation Department performed a turnover survey of the entire canal area. The results of this survey provided a bounded area that was less than the original estimated area, resulting in a reduction of waste volume for disposal.

Excavated Discharge and Intake Canal soil was unsuitable for immediate packaging and transporting, due to its high water content. Dump trucks were filled with Discharge Canal mud, transporting it to the SMF and dumping the load on the concrete floor. The drainage was collected and pumped into a holding tank. As the soil drained, it was stacked and allowed to further drain. This process allowed for a more rapid excavation of the Discharge Canal. The soil processing included draining, drying and the addition of lime to chemically react with the water for evaporation. The Environmental Team gained approval from the NCRWQCB and DTSC prior to mixing lime with reuse soils. This process required multiple soil manipulations utilizing heavy equipment. The Discharge Canal ACM piping was processed and packaged into IMs. Concrete and incidental rebar were direct-loaded into IMs at the canals.

Waste shipments were scheduled for off-site transport on an established schedule. During the period 2015 through 2018, the following shipments were made from HBPP for Canals:

2015	144 shipments	4.8 million pounds
2016	226 shipments	10.3 million pounds
2017	42 shipments	2.1 million pounds
2018	34 shipments	3.3 million pounds

9. Common Site Support

Actual costs during 2012-2014 being presented for reasonableness review total $1.2 million. Actual costs during 2015-2018 total $1.3 million.

a. Relocation of Trailer City

During the construction of the new HBGS facility, PG&E installed a complex of office trailers, known as Trailer City, in an area at the east end of the HBPP Decommissioning Project. There were 22 individual trailers units which were in configurations ranging from single-wide to six-wide. Half of the 3-acre area east of the Discharge Canal was covered by offices, roadways and sidewalks. The remaining area was occupied by the GWTS and used for associated laydown storage.

The area occupied by Trailer City was also needed to accommodate soil remediation, processing, load-out, storage and as a laydown area. Trailers became unoccupied when PG&E reduced its decommissioning staff and the CWC ramped up their staffing for the CW portion of the decommissioning.

Domestic water lines, sewer lines and conduit were capped at appropriate locations 4 inches below grade. Electrical conductors were de-terminated and removed from the conduits all the way back to their power sources. Trailer skirting, stairs and Americans with Disabilities Act (ADA) ramps were removed and discarded, unless lessors retained possession. Wood and metal scrap, anchors, porches and piers were either reused, transported to a local recycler, or disposed of in a Class II landfill. Seismic tie downs were saved for reuse, where practical. To prevent unauthorized entry and potential injury, doors were boarded over following completion of interior preparation. Two vendors removed their respective trailers in a planned sequence. Spotters were used as the oversized loads were carefully maneuvered through the site to exit.

Above-ground structures, poles, and a site emergency siren were removed from Trailer City. Telephone and data communication lines were also removed. Sidewalks, parking areas, truck wash station, concrete pads, concrete pedestals and firehose cabinets were removed and discarded.

This work was performed under the direction of Engineering staff and final inspections were performed. This work was completed in May 2014.

Costs incurred after the removal of Trailer City are attributed to rent costs for offsite office facilities.

b. Groundwater Treatment System

The GWTS was installed by HBPP during the self-perform portion of decommissioning. The GWTS was designed for treating site water at a calculated maximum incoming rate of 300 gallons per minute (gpm). The design basis did not consider the volume or in-leakage rate from the Intake and Discharge Canals, since at the time the GWTS design criteria was established, the plan was to dredge the sediment (wet remediation) and leave the canals in place. Safety concerns and reconsideration of the effectiveness of wet remediation led PG&E to select the alternative approach of dry removing canal sediments. Costs for installation of the GWTS were reviewed and approved in the 2015 NDCTP.

To adapt the GWTS for the process of dry removing the canals' sediment, a PTS that settles out most solids was deemed the more efficient and less costly alternative to GWTS outages for cleaning. The PTS was located adjacent to and connected to the GWTS. The PTS was added to remove entrained sediment to ensure that the GWTS was not overloaded and shut down, which would affect any scheduled work activities dependent on continuous water removal. Additionally, the PTS settling tanks provided storage capacity to allow short GWTS outages, while continuing to support work activities.

The GWTS was originally designed to process up to 300 gpm. The system was not designed to handle the processing needs resultant from dewatering the canals during sediment removal and removing the Caisson entirely. The decommissioning plan changed to include year-around excavation activity, concurrent excavation activity and the complete removal of the Caisson. As a risk mitigation effort to reduce the potential for non-compliant storm water and groundwater discharges, the CWC proposed to effectively double the capacity of the

GWTS by adding an additional sand filter, particulate filters and carbon filters. An additional resin tank was added to the original system to provide additional metals removal capacity and redundancy to the system. The original pumps and piping were reconfigured to allow flow rates up to 600 gpm.

GWTS expansion was successfully completed and tested to confirm the added capacity worked as planned. It was proven to be a useful expansion, as the system was operated well over 300 gpm on many occasions after the completed expansion. During the fall of 2017, the GWTS was split into two separately-operable 300 gpm systems. The major elements of the 2015 GWTS Expansion were relocated to the top of the hill adjacent to Building 26 and west of the Caisson. The new system location was required to enable remediation of contaminated soil from beneath the original GWTS footprint.

Costs in this category were for the GWTS specialty vendor and were incurred in 2015. The GWTS is managed by the CWC and costs are spread amongst the individual CWC projects.

c. GWTS Operations

The GWTS Operation scope is managed by the CWC and is described below.

The CWC trained and dedicated a group of individuals to the daily operation of the GWTS. Due to strict environmental standards imposed by local and state authorities the functioning of the many elements had to be monitored, maintained and managed to an approved procedure.

Every time water was to be transferred from a work face to the GWTS, a decision was made whether to route to the PTS or directly to influent tanks. Factors such as sampling, blending water to manage turbidity and/or pH levels, hold time for turbidity control (settling time) and storage during system maintenance would inform that decision. Once decided, water transfer was monitored and recorded on a daily report.

Field manual operations included: continuously recording conditions and actions on the daily report, including recirculation decisions, chemical injection pump calibrations, chitosan dosage rates and manual backwash activity; and visually monitoring water stream for pH, turbidity and flow via inline displays and comparing them to digital output displays during discharge. Staff worked irregular hours and weekends during higher-than-normal rains to ensure excavations were ready for the next shift's work. Treatment Technicians were required on site anytime the GWTS was in operation.

10. Engineering, Procurement and Construction Services

a. EPC Services

EPC was established as a separate cost category in the 2015 NDCTP in order to provide a single point of contact to manage a diverse set of vendors and necessary services to support the decommissioning project. Because the CWC was performing most of the work on the site, PG&E transferred the contracted site maintenance activities scope to the CWC. PG&E recognized that transferring an additional O&M-type scope to the CWC stood to benefit the project by allowing the CWC to control all activities on site. The CWC would be able to balance resources more effectively than multiple contractors could independently. The EPC work captured the additional support operations necessary to keep HBPP running efficiently and consolidated several scopes of work that fell outside the boundaries of the other CWP scope packages.

PG&E turned over the EPC Services program to the CWC in January 2014. PG&E requested that the CWC assume responsibility to implement the requirements of the approved SWPPP on file with the NCRWQCB. The CWC began providing labor, equipment and materials to maintain site compliance with the SWPPP. Following the transfer of the SWPPP EPC Scope, PG&E transferred housekeeping activities, the HBPP Safety Program, warehouse operations, general site maintenance, vendor oversight, scheduling coordination and work week manager EPC Scopes to the CWC in May 2014.

The above scopes were implemented and maintained by the CWC to support the site functions. Changes to the General Site Maintenance Scope in October 2014 added three categories to the EPC operations, including System Operations, Training Coordination/Liaison and Skilled Trades Activities and Light Industrial Support.

b. Other Services – Training

The CWC assumed administrative duties of the HBPP Training Department in 2014, maintaining HBPP's philosophy of implementing an extensive training program and compliance database. This was to ensure worker safety and to comply with Cal/OSHA. The CWC conducted over seven hundred and fifty training classes since assuming program responsibilities under the guidance of PG&E. These training classes were to ensure that the workforce was properly prepared to work on the site as new employees, or to requalify individuals so they could continue their assigned duties.

An offsite office space was used exclusively for training after the planned decommissioning of the on-site training space at HBPP. The training area included a break room, assembly room and staff offices. A shuttle van was available to employees needing transport from the job site to the offsite training space to attend scheduled classes.

The Training Coordinator/Liaison Services were performed in accordance with the HBPP QA Program.

F. Use of Experienced and Qualified Personnel

In the 2005 NDCTP decision, the Commission determined that "to reasonably undertake decommissioning a nuclear generating plant, PG&E…must employ properly trained experts who have experience relevant to decommissioning a nuclear plant to plan and perform the decommissioning."[3] In each NDCTP since that time, the Commission has concluded that PG&E had provided uncontested evidence that the work which had been completed to date was performed by qualified and experienced personnel.

To ensure project success, PG&E recruited a highly experienced and specialized group of managers with solid management skills, strong technical skills, industry specific knowledge, and the desire to see the project succeed through the critical phases. The low attrition rate, strong participation in professional and industry forums, and proven ability to solve unexpected

[3] D.07-01-003, Ordering Paragraph 6.

problems demonstrate PG&E's success. The combination of PG&E and contractor personnel with specialized skill sets has proven to be very cost effective. Industry evaluations, audits, NRC inspections, H&S records, and project accomplishments attest to the team's ability to manage the project within the project parameters.

All decommissioning activities at HBPP are overseen by PG&E's Director of Decommissioning, Loren Sharp. Mr. Sharp has extensive project management experience, including extensive experience in managing and disposing of toxic hazardous waste. In addition, he is a licensed nuclear engineer with substantial experience in managing plant operations. As Director of Decommissioning, Mr. Sharp has overseen more than 500 PG&E and contract employees and is responsible for ensuring that HBPP decommissioning is conducted safely and in accordance with the NRC and various other federal and state agencies.

Decommissioning activities are also overseen by the acting HBPP Deputy Director for Decommissioning, James Salmon, who reports to Mr. Sharp. These activities include environmental compliance, environmental remediation, waste management and site restoration. Mr. Salmon has degrees in chemistry and business administration and has nearly 40 years' experience in waste management, environmental program management and project management.

William Barley is responsible for the Site Closure Group, which includes the License Termination Plan, Final Status Surveys, site training and license termination interface with the NRC. Mr. Barley has a chemical engineering degree and is a certified Health Physicist. He has 40 years of nuclear experience and has held positions as a RP Manager, Senior Reactor Operator Engineer and NRC inspector. At HBPP, Mr. Barley supervises the License Termination Survey staff and manages the CAP, as well as regulatory affairs matters previously performed by the Decommissioning Manager, and Radiological Program management duties previously performed by the RP Manager.

Mr. Sharp's, Mr. Salmon's and Mr. Barley's qualifications are outlined in the attached Statements of Qualifications. The organizational structure which PG&E has established for ongoing decommissioning work is set forth in Chapter 8, Attachment A, HBPP DCE, Appendices B though F.

As is shown above, PG&E has satisfied the criteria for training and experience set forth by the Commission in D.07-01-003.

G. Comparison of Forecast and Actual SAFSTOR Expenditures

As authorized in Commission D.14-02-024, PG&E tracks its actual SAFSTOR expenses and "trues up" based on whether the amount collected in rates is greater than or less than the expenses actually incurred. Under collections will result in additional withdrawals from the NDTs, while over collections will be credited against decommissioning costs incurred by PG&E that would otherwise be recoverable from the NDTs.

Personnel who perform SAFSTOR O&M also perform substantial decommissioning tasks, and the true-up procedure avoids rate recovery duplications or omissions merely because of the way in which PG&E personnel account for and spend their time. If these individuals end up spending more time on decommissioning than on SAFSTOR, customers are held harmless through an additional contribution to the trust. Conversely, if these individuals actually spend more time on SAFSTOR than anticipated, PG&E will not suffer a shortfall merely because additional SAFSTOR activities are required in connection with decommissioning.

D.17-05-020 directed PG&E to track and explain differences between actual and forecast SAFSTOR O&M expenses.[4] For 2016, PG&E's actual SAFSTOR O&M costs exceeded the annual revenue requirement by $4.390 million. The adopted revenue requirement forecast was $9.357 million, and the 2016 actuals were $4.967 million. This over collection is attributable to individuals supporting the decommissioning activities and a discrepancy in the forecast that assumed a greater allocation of Administrative and General to the SAFSTOR activities than was actually incurred.

For 2017 PG&E's actual SAFSTOR O&M costs were over collected from the annual revenue requirement by $1.151 million. The adopted revenue requirement forecast was $5.024 million, and the 2017 actuals were $3.873 million. This over collection is attributable to less manpower required to maintain the NRC SAFSTOR requirements than was anticipated.

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[4] D.17-05-020, p. 64.

For 2018 PG&E anticipates that its forecast for SAFSTOR O&M costs will be over-collected from the annual revenue requirement by $1.950 million. The adopted revenue requirement forecast was $4.992 million, and the 2018 preliminary actuals are estimated to be $3.510 million. This over-collection is attributable to less manpower required to maintain SAFSTOR requirements than was anticipated.

H. Conclusion

In summary, the Commission should affirm the reasonableness and prudence of the completed projects as described in this chapter; find that PG&E has made reasonable efforts to retain and utilize sufficient qualified and experienced personnel; and find that PG&E adequately explained the difference between actual and forecast SAFSTOR expenditures.

TABLE 9-1
COMPLETED PROJECTS APPROVED COST ESTIMATE TO ACTUAL (2012 NDCTP)

A	B	C	D	E	F	G	H	Delta
2012 NDCTP CPUC Filing	2012-2014 Approved 2012 NDCTP Estimate		Amount Spent Presented for Reasonableness			Previously Presented and Approved	Spent Remaining for Future Reasonableness Review	Delta C-(F+G+H)
	Base	Nominal	2012-2014[1]	2015-2018	Total			
	378,802,217	398,622,050	34,289,776	-	34,289,776	227,153,626	7,630,505	129,548,143
1 - General Staffing	66,879,786	69,938,306	-	-	-	66,432,824	7,630,505	(4,125,023)
License Termination Survey	7,149,598	7,487,619	-	-	-	-	7,630,505	(142,886)
Overall Project/Civil Works Oversight	59,730,188	62,450,687			-	66,432,824		(3,982,137)
2 - Remainder of Plant Systems	51,287,467	53,421,149	41,535	-	41,535	43,748,081	-	9,631,534
Direct Labor	32,716,722	34,022,032	41,535	-	41,535	31,823,080	-	2,157,417
Liquid Radwaste Removal	6,938,936	7,320,409	-	-	-	4,282,774		3,037,635
Tools and Equipment	11,631,810	12,078,709	-	-	-	7,642,227	-	4,436,482
3 - Site Infrastructure	2,251,887	2,343,226		-		4,935,540		(2,592,314)
4 - Specific Project Costs	72,184,834	75,643,003	9,783,021	-	9,783,021	27,282,792		38,577,191
Reactor Vessel Removal	15,896,279	16,530,248	-	-	-	15,263,911		1,266,337
Turbine Building Demolition	14,370,353	14,940,563	-	-	-	12,018,881		2,921,682
Civil Works	41,918,202	44,172,193	9,783,021	-	9,783,021	-		34,389,172
Nuclear Facilities	41,376,133	43,601,017	9,656,521	-	9,656,521	-		33,944,496
Office Facilities	542,069	571,176	126,501	-	126,501	-		444,676
5 - Waste Disposal (Excludes Caisson / Canals)	50,762,743	53,876,290	5,494,905	-	5,494,905	46,507,268		1,874,117
Labor (Packaging and Handling)	11,512,031	12,241,660	-	-	-	10,874,350		1,367,310
Third Party Disposal Sites	36,620,246	38,850,851	5,494,905		5,494,905	31,867,488		1,488,459
Waste Handling Building	2,630,466	2,783,779	-	-	-	3,765,430		(981,651)
6 - Small Value Contracts	26,825,024	27,739,352	37,924	-	37,924	21,575,949		6,125,480
Small Dollar Vendor[1]	7,186,457	7,454,061	37,924	-	37,924	2,680,883		4,735,254
Specialty Contracts	19,638,567	20,285,292	-	-	-	18,895,065		1,390,227
7 - Spent Fuel Management	13,450,356	14,154,252	-	-	-	14,279,397		(125,145)
Security (PG&E)	10,126,024	10,690,990	-	-	-	11,235,555		(544,565)
ISFSI O&M	1,525,843	1,593,444	-	-	-	1,632,172		(38,729)
ISFSI Staffing / Engineering / Specialty Contracts	1,727,246	1,795,538	-	-	-	1,089,192		706,346
ISFSI Infrastructure Expense	-	-	-	-	-	77,231		(77,231)
NRC Fees	71,243	74,280	-	-	-	245,246		(170,966)
9 - Caisson	65,245,822	69,346,787	9,194,034	-	9,194,034	-		60,152,753
Field Work (Civil Works Contract)	58,556,128	61,976,019	9,194,034	-	9,194,034	-		52,781,985
Slurry Wall/CSM Wall	58,556,128	61,976,019	9,194,034	-	9,194,034	-		52,781,985
Waste Disposal	4,883,412	5,380,589						5,380,589
Packaging / Material Handling	1,806,283	1,990,179						1,990,179
10-Canals	23,704,100	25,642,441	8,379,236	-	8,379,236	-		17,263,205
Canal Removal	12,580,790	13,386,673	8,379,236	-	8,379,236	-		5,007,437
Canal Disposal	11,123,310	12,255,768	-	-	-	-		12,255,768
11 - Common Site Support	5,720,750	5,995,251	1,159,807	-	1,159,807	2,391,776		2,443,668
Relocation of Trailer City	2,542,000	2,688,812	888,774	-	888,774	-		1,800,039
Groundwater Treatment System Ops	761,474	792,786	271,033	-	271,033	14		521,739
Groundwater Treatment System	2,417,276	2,513,653				2,391,763		121,890
12 -EPC	489,447	521,993	199,315	-	199,315	-	-	322,678
EPC Services	489,447	521,993	199,315	-	199,315	-		322,678
Other Services - Training	-	-	-	-	-	-		-

Note: 1. Small Value Contracts Spend Includes $3,149 for costs incurred in 2011

TABLE 9-2
COMPLETED PROJECTS APPROVED COST ESTIMATE TO ACTUAL (2015 NDCTP)

A	B	C	D	E	F	G	H	
2015 NDCTP CPUC Filing	2015-2018 Approved 2015 NDCTP Estimate		Amount Spent Presented for Reasonableness			Previously Presented and Approved	Spent Remaining for Future Reasonableness Review	Delta C-(F+G+H)
	Base[1]	Nominal[2]	2012-2014	2015-2018	Total			
	415,768,624	443,560,039		365,887,901	365,887,901	5,254,094	34,301,629	38,116,416
1 - General Staffing	34,643,447	36,475,856	-	28,138,098	28,138,098	-	6,020,138	2,317,621
License Termination Survey	6,296,058	6,641,393	-		-	-	6,020,138	621,255
Overall Project/Civil Works Oversight	28,347,388	29,834,463	-	28,138,098	28,138,098			1,696,365
2 - Remainder of Plant Systems	5,104,925	5,283,992	-	4,587,091	4,587,091	-		696,901
Direct Labor	2,743,043	2,860,330	-	2,655,329	2,655,329	-		205,000
Radiation Protection	2,743,043	2,860,330		2,655,329	2,655,329			205,000
Tools & Equipment	2,361,882	2,423,662	-	1,931,762	1,931,762	-		491,900
RP Tools & Equipment	2,361,882	2,423,662	-	1,931,762	1,931,762	-		491,900
4 - Specific Project Costs	103,968,390	110,194,042	-	68,792,685	68,792,685	1,720,205	28,281,491	11,399,661
Reactor Vessel Removal	1,693,007	1,739,108	-	(736)	(736)	1,720,205		19,639
Civil Works	102,494,605	108,683,615	-	68,886,219	68,886,219	-		11,515,905
Nuclear Facilities Demolition	60,161,115	62,821,873	-	66,293,695	66,293,695	-		(3,471,822)
Administration Services	40,814,849	43,029,349	-	42,437,915	42,437,915	-		591,435
Restricted Area Prep	5,547,472	5,675,442	-	6,171,599	6,171,599	-		(496,158)
Refueling Building	8,304,579	8,496,126	-	9,170,035	9,170,035	-		(673,909)
Units 1, 2 and 3 Circulating Water Lines	2,722,521	2,785,325	-	6,612,272	6,612,272	-		(3,826,947)
Upper Yard Demolition	1,238,993	1,267,574	-	957,170	957,170	-		310,405
Temporary Facilities	1,532,701	1,568,057	-	944,705	944,705	-		623,352
Offices & Facilities Demolition	1,865,978	2,041,690	-	2,101,145	2,101,145	-		(59,454)
Final Site Restoration	37,253,566	40,412,905	-	-	-	-	28,281,491	12,131,414
Other Services/Letter of Credit	3,213,946	3,407,147	-	491,379	491,379	-		2,915,768
Disallowed Scope	(219,222)	(228,681)	-	(92,798)	(92,798)	-		(135,883)
5 - Waste Disposal (Excludes Caisson / Canals)	34,822,844	38,799,614	-	35,229,131	35,229,131	3,533,889	-	36,594
Third Party Disposal	32,601,773	36,485,244	-	35,229,131	35,229,131	1,293,653		(37,540)
Labor Packaging and Handling	2,221,071	2,314,370	-	-	-	2,240,236		74,134
6 - Small Value Contracts	12,960,489	13,562,375	-	11,017,677	11,017,677	-		2,544,697
Small Dollar Vendors	1,750,345	1,846,866	-	1,723,266	1,723,266	-		123,600
Small Dollar Vendors	1,750,345	1,846,866	-	1,723,266	1,723,266	-		123,600
Specialty Contracts	11,210,144	11,715,509	-	9,294,412	9,294,412	-		2,421,097
Environmental Contracts	1,041,989	1,121,875	-	1,512,840	1,512,840	-		(390,966)
Permitting	302,000	322,857	-	983,518	983,518	-		(660,661)
Specialty Consultants	9,866,156	10,270,777	-	6,798,054	6,798,054	-		3,472,724
7 - Spent Fuel Management	35,352,832	37,735,082	-	27,714,733	27,714,733	-		10,020,349
Security (PG&E)	24,152,470	25,910,839	-	21,937,592	21,937,592	-		3,973,248
ISFSI Operate & Maintain	2,180,894	2,316,519	-	1,912,651	1,912,651	-		403,868
ISFSI Staffing / Engineering / Specialty Contracts	3,346,908	3,517,087	-	1,877,811	1,877,811	-		1,639,276
ISFSI Infrastructure Expenses	5,490,000	5,792,821	-	1,812,492	1,812,492	-		3,980,328
NRC Fees	182,559	197,816	-	174,187	174,187	-		23,630
9 - Caisson	132,677,602	141,931,590	-	141,816,081	141,816,081	-		115,509
Field Work (Civil Works Contract)	77,189,053	81,405,385	-	80,613,876	80,613,876	-		791,509
Caisson	61,833,344	65,359,258	-	68,261,967	68,261,967	-		(2,902,708)
Slurry Wall/CSM Wall	12,641,528	13,211,889	-	10,575,080	10,575,080	-		2,636,809
Dewatering	2,714,181	2,834,238	-	1,776,830	1,776,830	-		1,057,408
Project Staffing	17,643,186	18,869,164	-	13,231,648	13,231,648	-		5,637,516
Waste Disposal	23,313,034	26,205,862	-	35,092,897	35,092,897	-		(8,887,035)
License Termination Survey	4,189,348	4,486,368	-	5,398,254	5,398,254	-		(911,887)
Tools & Equipment	1,253,037	1,301,563	-	763,662	763,662	-		537,901
Other	9,089,943	9,663,248	-	6,715,743	6,715,743	-		2,947,505
RP Discrete	1,338,207	1,425,435	-	1,498,091	1,498,091	-		(72,656)
Specialty Contracts	6,887,232	7,312,073	-	4,990,147	4,990,147	-		2,321,926
Specialty Contracts	5,274,446	5,586,229	-	3,988,979	3,988,979	-		1,597,250
Environmental Contracts	1,250,386	1,340,034	-	921,147	921,147	-		418,887
Specialty Permitting	362,400	385,810	-	80,020	80,020	-		305,790
Small Dollar Vendor	864,504	925,740	-	227,505	227,505	-		698,235
Small Dollar Vendor	864,504	925,740	-	227,505	227,505	-		698,235
10-Canals	44,242,713	46,962,435	-	38,670,562	38,670,562	-		8,291,873
Canal Removal	32,582,306	33,939,883	-	32,095,069	32,095,069	-		1,844,814
Canal Disposal	11,660,406	13,022,552	-	6,575,493	6,575,493	-		6,447,059
11 - Common Site Support	1,725,005	1,833,437	-	1,270,370	1,270,370	-		563,068
Relocation of Trailer City	1,398,085	1,497,542	-	928,129	928,129	-		569,412
Groundwater Treatment System Ops	34,579	35,303	-	35,303	35,303	-		0
Groundwater Treatment System	292,342	300,592	-	306,937	306,937	-		(6,345)
12-EPC	10,270,378	10,781,616	-	8,651,473	8,651,473	-		2,130,143
EPC Services	9,588,908	10,059,383	-	7,339,041	7,339,041	-		2,720,342
Other Services - Training	681,470	722,233	-	1,312,432	1,312,432	-		(590,200)

Notes:
1. HBPP decommissioning estimated cost to complete approved in D.17-05-020 with contingency allocated to each category as authorized through AL 5203-E effective Mar 23, 2017
2. Amount of authorized expenditures escalated to nominal dollars in the year planned to spend Jan 1, 2015 through Dec 31, 2018 (Includes complete budget for all CWC scope of work)
3. Reactor Vessel Removal has a credit of $736 due to late invoice credit.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

CONTRIBUTIONS FUNDING THE NUCLEAR DECOMMISSIONING TRUST

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
CONTRIBUTIONS FUNDING THE NUCLEAR DECOMMISSIONING TRUST

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
CONTRIBUTIONS FUNDING THE NUCLEAR DECOMMISSIONING TRUST

A. Introduction and Purpose

This chapter presents Pacific Gas and Electric Company's (PG&E) forecast of annual contributions to the nuclear decommissioning (ND) qualified master Trust (NDT or ND Trust) for the Diablo Canyon Power Plant (DCPP) Units 1 and 2 and Humboldt Bay Power Plant Unit 3 (HBPP), beginning January 1, 2020. In addition, this chapter reviews the updated assumptions including the escalation rates used to forecast nominal decommissioning costs for DCPP and HBPP, ND Trust balances, equity turnover rates and the forecast of expected rates of return on NDT assets to ensure that adequate funds will be available for decommissioning activities. Lastly, this chapter describes PG&E's compliance with the 2009 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) Phase 2 Decision directive to providing a summary of actual trust fund performance covering the previous three years compared to the prior NDCTP forecast performance.[1]

B. Summary of Request

PG&E requests California Public Utilities Commission (Commission) approval of annual contributions to the Trust of $226.715 million for DCPP Unit 1, $151.141 million for DCPP Unit 2, and $3.791 million for HBPP, beginning January 1, 2020. The annual contributions are shown in Table 10-1 below. The associated revenue requirements are presented in Chapter 11.

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1 Decision (D.) 13-01-039 Ordering Paragraph (OP) 12. The Commission reiterated this directive in the 2015 NDCTP. D.17-05-020, p 65.

TABLE 10-1
DIABLO CANYON POWER PLANT UNITS 1 AND 2 AND HUMBOLDT BAY POWER PLANT UNIT 3 CURRENT AND PROPOSED CONTRIBUTIONS
(MILLIONS OF DOLLARS)

Line No.		D.17-05-020	A.18-12-XXX
1	Diablo Canyon Unit 1 – Nov. 2024	–	$226.715
2	Diablo Canyon Unit 2 – Aug. 2025	–	151.141
3	Total	–	$377.856
4	HBPP	$62.360	$3.791

C. Background

In 1983, the Commission ordered the California utilities with nuclear facilities to begin forecasting eventual costs of ND, "to assure that adequate funds will be available for decommissioning nuclear generating facilities, and to ensure that the costs of decommissioning will be distributed equitably over time among the customers who benefit from operation of the nuclear power plants."[2] D.83-01-013 approved a separate, externally-managed sinking fund, dedicated for decommissioning costs. The decision states:

> …annual contributions will be set so that the principal plus accumulated earnings should cover the cost of decommissioning at the time decommissioning is expected to occur.

In 1988, PG&E completed the first step in the decommissioning of HBPP. That step involved placing the unit into a custodial mode of decommissioning defined by the Nuclear Regulatory Commission (NRC) as Safe Storage. PG&E began actively decommissioning HBPP in 2009, shortly after the completion of the Independent Spent Fuel Storage Installation (ISFSI). Based on PG&E's current schedule of decommissioning activities, decommissioning of HBPP is expected to conclude in 2033.

DCPP Units 1 and 2 have been safely generating electricity for Central and Northern California since 1984 and 1985, respectively. The two nuclear reactors are currently licensed to operate until 2024 and 2025.

D. Contributions Estimating Methodology

The NDT annual contributions are calculated based on the following estimating methodology. First, the decommissioning cost estimates for DCPP

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2 D.83-01-013 (52 P.U.R. 4th 6118).

are estimated in 2017 dollars in Chapter 4, and are estimated in 2018 dollars for HBPP in Chapter 8. These cost estimates are escalated to the future years in which the decommissioning activities will occur. The decommissioning costs from Chapters 4 and 8 are assigned to five main categories: PG&E labor, equipment and materials, contract labor, burial costs of low-level radioactive waste (LLRW), and other.[3] Escalation factors, shown in Table 10-2 for DCPP, and Table 10-4 for HBPP, are applied to the annual costs to arrive at forecasted nominal estimates. Second, annual contributions to the NDT are calculated such that the estimated end-of-year 2017 market values of the NDT plus annual contributions and earnings on the NDT, less associated income tax payments on those earnings, will equal the cost of each respective decommissioning at its time of occurrence.

For DCPP, the NDT funding period ends in 2024 for Unit 1 and 2025 for Unit 2. For HBPP, the NDT funding period ends in 2022.

Contributions are estimated using the following assumptions:

- Escalation rates for each of the five main decommissioning cost categories, as discussed in sections D.1. for DCPP, and D.2. for HBPP, below; and
- Estimated rates of return on the Trust, equity turnover percentages, asset allocations, and equity ramp-down assumptions, as presented in sections F through H below.

1. Assumed Escalation Rates – DCPP

For each of the five main decommissioning cost categories, the constant dollar costs are escalated to the period when decommissioning costs will be incurred using the escalation rates described below. For DCPP, costs are escalated annually from the 2018 Decommissioning Cost Estimate through 2076, when the last of the decommissioning costs are forecasted to be incurred. The adopted escalation assumptions from the prior case (D.17-05-020) and updated proposed assumptions are shown in Table 10-2

[3] "Other" includes costs such as engineering and decommissioning preparations (e.g., planning for permanent defueling of the reactor, preparation and filing of a Post-Shutdown Decommissioning Activities Report with the NRC, and shutdown preparation), property tax, insurance premiums, LLRW recycling costs, and plant energy costs.

below. Average escalation rates are shown for comparison purposes only, as actual rates change each year.

TABLE 10-2
DIABLO CANYON POWER PLANT
AVERAGE ANNUAL ESCALATION RATES AND ASSUMPTIONS

Line No.	Cost Category	D.17-05-020	A.18-12-XXX	Source
1	PG&E Labor	2.92%	3.30%	Prior Case: Blended rate based on PG&E union contract and non-represented employees. Consistent with 2017 General Rate Case (GRC) showing. Proposal: No change in methodology. Consistent with 2020 GRC filing.
2	Equipment and Materials	1.96%	1.44%	Prior Case: Weighted proportional to total costs based on 91 percent Gross Domestic Product (GDP) implicit price deflator for consumables and 9 percent Producer Price Index (PPI) for machinery and equipment. Proposal: No change in methodology. Weights updated based on 41 percent consumable materials and 59 percent heavy duty equipment.
3	Contract Labor	3.10%	3.09%	Prior Case: Employment Cost Index (ECI) for total private compensation. Proposal: No Change in Methodology.
4	LLRW Burial Costs	6.64%	6.70%	Prior Case: Average growth rate of pressurized water reactor (PWR) burial costs series over 28 years from NUREG-1307 Reports. Proposal: Average growth rate of PWR burial costs series over 30 years from NUREG-1307 Reports. Method consistent with prior case.
5	Other	2.19%	2.21%	Prior Case: GDP Implicit Price Deflator. Proposal: No Change in Methodology.

Note: Escalation rates are an average of the annual escalation rates over the period of forecasted decommissioning cost activity.

a. PG&E Labor

PG&E labor costs comprise approximately $1,343.9 million or 29 percent of total decommissioning costs. PG&E proposes to use a 3.30 percent average escalation rate to escalate PG&E Labor costs in 2018 and thereafter. The rates are based on a blend of PG&E union contracts and non-represented employees for each period and are consistent with what will be filed in PG&E's 2020 GRC and with the prior NDCTP.

b. Equipment and Materials

Equipment and materials costs comprise approximately $537.3 million or 12 percent of total decommissioning costs. Based on a review of the costs, approximately 41 percent are categorized as consumable materials and 59 percent are categorized as heavy-duty equipment. PG&E proposes to escalate the costs based on a weighting of the following indices: (1) for consumable materials, comprising 41 percent, the forecasted changes in the GDP implicit price deflator; and (2) for heavy-duty equipment, comprising 59 percent, the forecasted changes in the PPI for machinery and equipment. Both indices are available through 2048. For the period from 2049 to 2076, a 3-year average of the 2046-2048 weighted indices was used. This method is consistent with the 2015 NDCTP.

c. Contract Labor

Contract labor costs comprise approximately $976.7 million or 21 percent of total decommissioning costs. Consistent with the prior NDCTP, PG&E proposes to escalate contract labor costs based on the forecasted changes in the ECI for total private compensation. The ECI compensation series includes the changes in wages and salaries (not seasonally adjusted) and the costs of employee benefits for private industry workers. The use of the ECI series is appropriate, as it is a principal economic indicator of the changes in total compensation. The index is available through 2048. For the period from 2049 to 2076, a 3-year average of the 2046-2048 index was used. This method is consistent with the prior NDCTP.

d. LLRW Burial and Disposal

LLRW burial and disposal costs comprise approximately $895.0 million or 19 percent of total decommissioning costs. Consistent with the prior NDCTP, PG&E proposes to use 6.70 percent, based on the average annual change in LLRW burial and disposition costs from 1986 to 2016, of the PWR burial sites and waste vendors published in

NUREG-1307 (NUREG report).[4] The NUREG report, which is updated periodically, provides estimates of radioactive waste burial and disposition costs by site and by year for licensees to use in developing ND cost estimates and analysis.

In forecasting the future cost of LLRW disposal, there continues to be few data points, a lack of sites and a great deal of uncertainty. To the extent that actual contract data is not available, PG&E believes the continued reliance on the NUREG report estimates is a reasonable and consistent method of escalation of LLRW costs. This method is consistent with the prior NDCTP.

e. Other

Other costs comprise approximately $898.3 million or 19 percent of total decommissioning costs. PG&E proposes to use the forecasted changes in the GDP implicit price deflator index for escalation of other costs. The GDP implicit price deflator provides a reasonable and objective measurement of price changes and inflationary trends in other costs. The index is available through 2048. For the period from 2049 to 2076, a 3-year average of the 2046-2048 index was used. This method is consistent with the prior NDCTP.

Table 10-3 presents the decommissioning costs for DCPP on a constant and nominal dollar basis, using the proposed escalation factors discussed above. The cost estimate in Table 10-3 includes $37 million of decommissioning planning activities as described in Chapter 3. It excludes the incremental planning activities of $150 million for which PG&E is seeking separate revenue recovery as described in Chapter 11.

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[4] Table 2.1, NUREG-1307, Rev 16, Final Report, published March 2017. The report provides escalation factors for the waste burial/disposition component of the decommissioning fund requirement, as required by the Code of Federal Regulations (10 CFR 50.75(c)(2)).

TABLE 10-3
DIABLO CANYON POWER PLANT
COST OF DECOMMISSIONING IN CONSTANT AND NOMINAL DOLLARS
(MILLIONS OF DOLLARS)

Line No.		D.17-05-020 2024-2062	A.18-12-XXX 2024-2076
1	Constant Dollar Cost	(2014)	(2017)
2	PG&E Labor	$682.270	$1,343.897
3	Equipment and Materials	341.158	537.301
4	Contract Labor	671.893	976.661
5	LLRW Burial and Disposal	326.312	894.998
6	Other	547.341	898.292
7	Total	$2,568.974	$4,651.149
8	Nominal Dollar Cost		
9	PG&E Labor	$1,159.049	$2,503.744
10	Equipment and Materials	486.410	694.342
11	Contract Labor	1,136.059	1,780.256
12	LLRW Burial and Disposal	831.312	3,700.319
13	Other	939.535	1,391.093
14	Total	$4,552.365	$10,069.754

2. Assumed Escalation Rates – HBPP

For each of the five remaining decommissioning cost categories, HBPP constant dollar costs are escalated to the period when remaining decommissioning activities will be incurred, using the escalation rates described below. Costs are escalated annually from the 2018 cost study period, through the end of decommissioning in 2033.[5] The adopted escalation assumptions from the prior case (D.17-05-020) and updated proposed assumptions are shown in Table 10-4 below. Average escalation rates are shown for comparison purposes only, as actual rates change each year.

5 All demolition and restoration activities associated with decommissioning HBPP, except for spent fuel disposal and ISFSI decommissioning, are anticipated to be completed by 2020. Spent fuel storage activities are forecast to continue to the end of 2033.

TABLE 10-4
HUMBOLDT BAY POWER PLANT UNIT 3
AVERAGE ANNUAL ESCALATION RATES AND ASSUMPTIONS

Line No	Cost Category	D.17-05-020	A.18-12-XXX	Source
1	PG&E Labor	2.91%	3.30%	Prior Case: Blended rate based on PG&E union contract and non-represented employees. Consistent with 2017 General Rate Case (GRC) showing. Proposal: No change in methodology. Consistent with 2020 GRC filing.
2	Equipment and Materials	1.64%	2.50%	Prior Case: Weighted proportional to total costs based on 91 percent GDP implicit price deflator for consumables and 9 percent PPI for machinery and equipment. Proposal: No change in methodology. Weights updated based on 98 percent consumable materials and 2 percent heavy duty equipment.
3	Contract Labor	3.07%	3.23%	Prior Case: ECI for total private compensation. Proposal: No change in methodology.
4	LLRW Burial Costs	5.0%	5.0%	Prior Case: Confidential blended rate based in part on actual pricing in accordance with stipulation with the Office of Ratepayer Advocates. Proposal: No change in methodology.
5	Other	1.97%	2.20%	Prior Case: GDP Implicit Price Deflator. Proposal: No change in methodology.

a. PG&E Labor

PG&E labor costs comprise approximately $89.9 million or 33 percent of remaining decommissioning costs. PG&E proposes to use a 3.30 percent average escalation rate to escalate PG&E Labor costs in 2019 and thereafter. The rates are based on a blend of PG&E union contracts and non-represented employees for each period and are consistent with what will be filed in PG&E's 2020 GRC, and with the prior NDCTP.

b. Equipment and Materials

Equipment and materials costs comprise approximately $1.4 million or 0.5 percent of remaining decommissioning costs. PG&E proposes to escalate the costs based on a weighting of the following indices:

(1) 98 percent of the forecasted changes in the GDP implicit price deflator; and (2) 2 percent of the forecasted changes in the PPI for machinery and equipment. This methodology is consistent with the prior NDCTP.

c. Contract Labor

Contract labor costs comprise approximately $136.7 million or 50 percent of remaining decommissioning costs. Consistent with the prior NDCTP, PG&E proposes to escalate the contract labor costs based on the forecasted changes in the ECI for total private compensation. The ECI compensation series includes the changes in wages and salaries (not seasonally adjusted) and the costs of employee benefits for private industry workers. The use of the ECI series is appropriate, as it is a principal economic indicator of the changes in total compensation. This method is consistent with the prior NDCTP.

d. LLRW Burial and Disposal

LLRW burial costs comprise approximately $20.9 million or 8 percent of remaining decommissioning costs. PG&E proposes to use a 5 percent blended escalation rate based on actual HBPP LLRW burial and disposal contracts.

e. Other

Other costs comprise approximately $24.3 million or 9 percent of remaining decommissioning costs. PG&E proposes to use the forecasted changes in the GDP implicit price deflator for escalation of other costs. The GDP implicit price deflator provides a reasonable and objective measurement of price changes and inflationary trends in other costs. This method is consistent with the prior NDCTP.

Table 10-5 presents the decommissioning costs for HBPP on a constant and nominal dollar basis, using the proposed escalation factors above. The cost estimate in table 10-5 includes the actual decommissioning spend of $15 million for the months of November and December in 2017, and the estimates for 2018-2033. The November and December 2017 costs are included as they had not been withdrawn from the trust by December 31, 2017, the starting point used for contribution modeling.

TABLE 10-5
HUMBOLDT BAY POWER PLANT UNIT 3
COST OF REMAINING DECOMMISSIONING IN CONSTANT AND NOMINAL DOLLARS
(MILLIONS OF DOLLARS)

Line No.		D.17-05-020 2015-2030	A.18-12-XXX 2019-2033
1	Constant Dollar Cost	2014	2018
2	PG&E Labor	$88.290	$89.898
3	Equipment and Materials	4.800	1.361
4	Contract Labor	301.284	136.675
5	LLRW Burial Costs	73.075	20.946
6	Other	63.833	26.323
7	Total	$531.282	$273.203
8	Nominal Dollar Cost		
9	PG&E Labor	$109.596	$112.552
10	Equipment and Materials	4.938	1.382
11	Contract Labor	330.425	152.221
12	LLRW Burial Costs	84.824	24.630
13	Other	68.983	28.706
14	Total	$598.766	$319.491

E. Trust Balances

PG&E's qualified NDT for DCPP and HBPP is an externally managed, separate legal entity.[6] It is taxed on its investment earnings at a reduced federal tax rate of 20 percent.[7]

Table 10-6 shows the balances in the NDT as of December 31, 2015, and as of December 31, 2017.

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6 California Public Utilities Code Section 8325.

7 I.R.C 468A(e)(2)(a).

TABLE 10-6
TRUST BALANCES OF DIABLO CANYON AND HBPP
(MILLIONS OF DOLLARS)

Line No.		D.17-05-020	A.18-12-XXX
1	Date of Fund Balance Update	12/31/2015	12/31/2017
2	Diablo Canyon Unit 1	$1,126.739	$1,374.308
3	Diablo Canyon Unit 2	$1,474.283	$1,797.696
4	Subtotal, Diablo Canyon	$2,601.022	$3,172.004
5	HBPP	192.543	150.375
6	Total	$2,793.565	$3,322.379

As of December 31, 2017, the DCPP and HBPP NDT values have grown by $528 million from $2,794 million as of December 31, 2015 to $3,322 million as of December 31, 2017. The revenue requirement for the 2015 previous NDCTP triennial period (2017-2019) reflected NDT balances as of December 31, 2015 in accordance with the Commission order and Internal Revenue Service requirements. In addition, in accordance with D.13-01-039, OP 12, Tables 10-9 and 10-10 provide a comparison table of projected and actual NDT rates of return for the years 2016[8] and 2017.

F. Return on Equity

Russell Investments (Russell) provides PG&E with forecast rates of return on various asset classes. Russell is a leading investment consultant and investment manager serving institutional clients in over 35 countries. Russell publishes forecast rates of return for 5-, 10-, and 20-year periods. For DCPP, PG&E uses Russell's 20-year return forecasts for equity and fixed income as this most closely matches the long-term investment horizon of the DCPP NDT assets. For HBPP, PG&E uses Russell's 10-year return forecasts for equity and fixed income as this is more aligned with HBPP's remaining decommissioning life.

For the return on equity, PG&E uses Russell's forecast returns for United States (U.S.) equity and global ex-U.S. equity. Following the investment policy weightings, PG&E weights these components 70 percent U.S. equity and

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8 Although the revenue requirement period for the prior NDCTP is 2017-2019, PG&E provides the actual vs forecasted trust rates of return for the Diablo Canyon and HBPP NDTs for 2016 as 2016 actual returns were not known until after the 2015 NDCTP was filed.

30 percent global ex-U.S. equity to arrive at a composite expected return on equity of 8.06 and 8.12 percent for DCPP and HBPP, respectively. Comparisons of PG&E's proposed return on equity assumptions and the adopted return on equity assumptions approved in the 2015 NDCTP are provided in Tables 10-7 and 10-8 below.

1. Equity Turnover Rate

In the last several NDCTPs, the Commission has accepted PG&E's calculating the annual equity turnover rates by averaging the actual equity turnover rates from prior years. Consistent with this methodology, PG&E again averages recorded equity turnover rates for both the non-U.S. equity and U.S. equity markets from 2008 through 2017. The resulting average equity turnover rate is approximately 11 percent.

G. Return on Fixed Income

The fixed income portfolio is invested against two different benchmarks. 70 percent of the portfolio is invested against the Barclays Capital U.S. Treasury Bond Index. For this portion of the portfolio, PG&E uses Russell's expected return on U.S. government bonds, 3.7 and 3.0 percent for DCPP and HBPP, respectively.

The remaining 30 percent of the portfolio is invested against a custom benchmark. PG&E worked with one of its investment managers, BlackRock, to design a custom benchmark with a goal of achieving a higher risk-adjusted return than the current Treasury benchmark. The custom benchmark includes corporate, high yield, asset-backed, municipal and Treasury bonds. Using expected return assumptions from Russell Investments, PG&E forecasts an expected return from this portion of the portfolio at 4.4 and 3.62 percent for DCPP and HBPP, respectively.

For the total fixed income portfolio, PG&E forecasts an expected return of 3.9 percent for Diablo Canyon, and an expected return of 3.19 percent for HBPP, which is calculated as a weighted average of the Treasury portfolio and the custom portfolio. A comparison of PG&E's proposed return on fixed income assumptions and the adopted return on fixed income assumptions approved in the 2015 NDCTP are provided in Tables 10-7 and 10-8 below.

H. Asset Allocation

The Nuclear Facilities Decommissioning Master Trust Committee (Committee) sets the asset allocation and has elected to set the equity exposure for the Diablo Canyon NDT at 60 percent, 30 percent of which is non-U.S. equity. The equity allocation for the HBPP NDT is 6 percent, reflecting the short investment horizon for these NDT assets. Fixed income makes up the remainder of the allocation, 40 percent for Diablo Canyon and 94 percent for HBPP. The forecast rates of return reflect this asset allocation.

1. Asset Liability Study

In 2018 the Committee engaged Callan Associates (Callan) to develop an asset allocation glide path for DCPP NDT assets. Callan is a well-known investment consulting firm that has produced analysis on NDT investment matters for the Committee, the Commission and other utilities across the country dating back to 1991.

An asset liability study uses Monte Carlo simulation to evaluate potential future scenarios (in this case 2,000) of asset returns and the impact of inflation on decommissioning expenditures. The study analyzes the trade-off between risk and reward of various asset allocations and is used by the Committee to select an appropriate asset allocation. Similar to the prior study Callan developed a glide path approach to asset allocation rather than the typical static allocation. A glide path gradually reduces the allocation to equities as the investment horizon decreases and decommissioning spending draws near. Reducing the exposure to equities like this reduces the risk that a bear market for equities would cause significant losses to NDT assets shortly before they are required for decommissioning expenditures. The glide path adopted by the Committee is shown in Table 10-11.

I. Table Comparison of Expected Returns and Equity Turnover Assumptions Used in the Prior NDCTP Proceeding Versus Current Proceeding

TABLE 10-7
DIABLO CANYON POWER PLANT
EXPECTED RETURN ASSUMPTIONS
(MILLIONS OF DOLLARS)

Line No.		A.16-03-006	A.18-12-XXX
1	Asset Allocations and Pre-Tax Returns		
2	Equity	60.0%	60.0%
3	Fixed Income	40.0%	40.0%
4	Equity Rate of Return	7.7%	8.1%
5	Equity Return, Net of Fees	7.6%	8.0%
6	Fixed Income Rate of Return	3.6%	3.9%
7	Fixed Income Return, Net of Fees	3.5%	3.8%
8	Income Tax Rate on Equity Earnings	27.1%	27.1%
9	Income Tax Rate on Fixed Income Earnings	20.7%	20.7%
10	Combined Overall After-Tax/After Fees Return		
11	Equity	4.1%	4.3%
12	Fixed Income	1.1	1.2
13	Total	5.2%	5.5%
14	Equities Ramp Down Assumption (i.e. converted to fixed income investments)	Per glide path	Per glide path
15	Average Equity Turnover rate	11.0%	11.0%

TABLE 10-8
HUMBOLDT BAY POWER PLANT UNIT 3
EXPECTED RETURN ASSUMPTIONS
(MILLIONS OF DOLLARS)

Line No.		A.16-03-006	A.18-12-XXX
1	Asset Allocations and Pre-Tax Returns		
2	Equity Allocation	6.0%	6.0%
3	Fixed Income Allocation	94.0%	94.0%
4	Equity Rate of Return	7.7%	8.1%
5	Equity Return, Net of Fees	7.6%	8.0%
6	Fixed Income Rate of Return	3.6%	3.2%
7	Fixed Income Return, Net of Fees	3.5%	3.1%
8	Income Tax Rate on Equity Earnings	27.1%	27.1%
9	Income Tax Rate on Fixed Income Earnings	20.7%	20.0%
10	Combined Overall After-Tax/After Fees Return		
11	Equity	0.4%	0.4%
12	Fixed Income	2.6%	2.3%
13	Total	3.0%	2.7%
14	Average Equity Turnover rate	11.0%	11.0%

J. Table Comparison of Projected Rate of Return Assumptions Used in the Prior NDCTP Proceeding Versus Actual Rate of Return

TABLE 10-9
DIABLO CANYON POWER PLANT
COMPARISON OF ACTUAL AND PROJECTED
RATES OF RETURN FOR 2016-2017
(RETURNS ARE AFTER FEES AND TAXES)

Line No.		2016	2017
1	2015 NDCTP Return Projection	5.23%	5.23%
2	Actual Rate of Return	6.63%	14.35%

TABLE 10-10
HUMBOLDT BAY POWER PLANT UNIT 3
COMPARISON OF ACTUAL AND PROJECTED
RATES OF RETURN FOR 2016-2017
(RETURNS ARE AFTER FEES AND TAXES)

Line No.		2016	2017
1	2015 NDCTP Return Projection	3.04%	3.04%
2	Actual Rate of Return	1.48%	3.65%

K. Table Asset Allocation Glidepath for Diablo Canyon

TABLE 10-11
DIABLO CANYON POWER PLANT
ASSET ALLOCATION GLIDEPATH

Year	U.S. Equity	Non-U.S. Equity	Total Equity	Fixed Income	Cash	Total
2018	42%	18%	60%	40%	–	100%
2019	39%	17%	55%	45%	–	100%
2020	35%	15%	50%	50%	–	100%
2021	32%	14%	45%	55%	–	100%
2022	27%	12%	39%	61%	–	100%
2023	25%	11%	35%	65%	–	100%
2024	22%	9%	31%	69%	–	100%
2025	20%	8%	28%	72%	–	100%
2026	19%	8%	27%	73%	–	100%
2027	20%	8%	28%	72%	–	100%
2028	20%	8%	28%	72%	–	100%
2029	20%	8%	28%	72%	–	100%
2030	20%	9%	29%	71%	–	100%
2031	20%	9%	29%	71%	–	100%
2032	18%	8%	25%	75%	–	100%
2033	15%	7%	22%	78%	–	100%
2034	14%	6%	20%	80%	–	100%
2035	14%	6%	20%	80%	–	100%
2036	14%	6%	20%	80%	–	100%
2037	15%	7%	22%	78%	–	100%
2038	19%	8%	27%	73%	–	100%
2039	27%	12%	39%	61%	–	100%
2040	32%	14%	46%	54%	–	100%
2041	32%	14%	45%	55%	–	100%
2042	31%	13%	44%	56%	–	100%
2043	29%	13%	42%	58%	–	100%
2044	29%	12%	41%	59%	–	100%
2045	28%	12%	40%	60%	–	100%
2046	27%	11%	38%	62%	–	100%
2047	25%	11%	36%	64%	–	100%
2048	25%	11%	35%	65%	–	100%
2049	23%	10%	33%	67%	–	100%
2050	21%	9%	30%	70%	–	100%
2051	20%	8%	28%	72%	–	100%
2052	17%	7%	24%	76%	–	100%
2053	14%	6%	20%	80%	–	100%
2054	11%	5%	15%	85%	–	100%
2055	8%	3%	11%	89%	–	100%
2056	4%	2%	6%	94%	–	100%
2057	2%	1%	3%	97%	–	100%
2058	1%	0%	1%	99%	–	100%
2059	0%	0%	0%	100%	–	100%
2060	0%	0%	0%	100%	–	100%
2061	0%	0%	0%	100%	–	100%
2062	0%	0%	0%	100%	–	100%

L. Internal Revenue Service Schedule of Ruling Amounts

PG&E is required to obtain a new Schedule of Ruling Amounts (SRA) reflecting the updated funding assumptions approved by the Commission in this NDCTP.

Federal Treasury regulations require that the SRA be calculated based on fund balances as of the most-recent year-end.[9] Immediately following a final decision in this proceeding, PG&E will file an advice letter with the Commission to update the annual decommissioning revenue requirements and contribution amounts based on the assumptions adopted in this NDCTP using the most-recent year-end Trust fund balances. Depending on the trust fund balances as of the most-recent year-end (which will depend on actual earnings of the fund vs. earnings forecasts), the revenue requirement (and corresponding contribution) may increase (in the case of reduced trust earnings) or decrease (in the case of higher trust earnings).

M. Conclusion

PG&E requests that the Commission adopt the forecasted rates of return and escalation factors set forth in this chapter for purposes of establishing the necessary contributions to the NDT.

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9 Treas. Reg. § 1.468A-3(h)(2)(vii)(D).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

TRUST CONTRIBUTION AND

PLANNING ACTIVITIES REVENUE REQUIREMENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
TRUST CONTRIBUTION AND
PLANNING ACTIVITIES REVENUE REQUIREMENTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
TRUST CONTRIBUTION AND PLANNING ACTIVITIES REVENUE REQUIREMENTS

A. Introduction

1. Purpose and Scope of Chapter

The purpose of this chapter is to present the Nuclear Decommissioning Trust (NDT) contribution and Diablo Canyon Power Plant (DCPP) decommissioning planning activities revenue requirements needed to support Pacific Gas and Electric Company's (PG&E) Nuclear Decommissioning (ND) beginning January 1, 2020. The revenue requirement calculations presented here comprise all revenues needed to fund PG&E's DCPP and Humboldt Bay Power Plant (HBPP) NDT based on the contributions developed in Chapter 10 and the costs of DCPP pre-shutdown decommissioning planning activities presented in Chapter 3.

2. Summary of Proposal

PG&E's cost of service, as expressed in revenue requirements, is calculated based on PG&E's planned NDT contributions and DCPP pre-shutdown planning activities. Specifically, PG&E is seeking recovery of a California Public Utilities Commission (CPUC or Commission) jurisdictional annual revenue requirement of $417.877 million beginning January 1, 2020. As presented in Table 11-1, the $417.877 million includes three separate revenue requirement components.

TABLE 11-1
PRESENT AND PROPOSED REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

Line No.	Description	Present 2019	Proposed 2020	Increase/ (Decrease)
1	DCPP Pre-shutdown Planning Activities	–	$30,295	$30,295
2	DCPP NDT Contribution	–	383,731	383,731
3	HBPP NDT Contribution	$63,386	3,850	(59,536)
4	HBPP Safe Storage (SAFSTOR)	4,401	–	(4,401)
5	Total	$67,787	$417,877	$350,090

(a) PG&E Prepared Testimony, Chapter 8, Section I describes why PG&E is not seeking a further revenue requirement for HBPP SAFSTOR in this filing.

This $417.877 million annual revenue requirement represents a $350.090 million increase from the 2019 authorized revenue requirement of $67.787 million.[1] At the end of this chapter, Table 11-3 summarizes the revenue requirements to fund the DCPP pre-shutdown decommissioning planning activities for 2020-2024, and Table 11-4 presents in detail a summary of the total NDT contribution revenue requirement.

3. Organization of the Remainder of This Chapter

The remaining sections of this chapter are organized as follows:

- Section B – Current Cost Structure;
- Section C – DCPP Pre-Shutdown Decommissioning Planning Activities Revenue Requirement and Cost Recovery Proposal;
- Section D – DCPP Units 1 and 2 and HBPP Unit 3 NDT Contribution Revenue Requirements;
- Section E – NDT Contribution Revenue Requirements Cost Recovery Proposal;
- Section F – Conclusion; and
- Section G – Tables.

B. Current Cost Structure

PG&E recovers authorized revenue requirements for ND services through the ND rate component in electric rates. The revenue requirements used to set these rates were last authorized in PG&E's 2015 Nuclear Decommissioning

[1] Advice Letter (AL) 5080-E.

Cost Triennial Proceeding (NDCTP), Decision (D.) 17-05-020, as implemented by subsequent AL filings. In compliance with Ordering Paragraph 1 of D.17-05-020, PG&E filed AL 5080-E to implement the 2017-2019 NDT contribution revenue requirement as described and adjusted in the decision.

C. DCPP Pre-shutdown Decommissioning Planning Activities Revenue Requirement and Cost Recovery Proposal

Table 3-1 in Chapter 3 discusses PG&E's request to spend $187.848 million (2017$) for decommissioning planning activities by the end of 2024. As shown in Table 11-2 below, the $187.848 million in planning activities costs were escalated to a nominal amount of $214.124 million using the proposed escalation factors in Chapter 10. The $214.124 nominal planning activities amount was reduced for the $37.2 million or 3 percent that can be withdrawn from the NDT. As noted in Chapter 3, prior to plant shutdown, NRC regulations limit PG&E's access to the NDT funds to 3 percent of the generic decommissioning formula funding amount, which equates to $37.2 million.[2] The $37.2 million is expected to cover decommissioning planning activities costs through part of 2019. To calculate the average annual spend net of the $37.2 million trust withdrawal amount, the balance of spend for the years 2019-2022 was totaled and divided by three years, and the balance of spend for years 2023-2024 was totaled and divided by two years. An annual average spend has been developed for the periods 2020-2022 and 2023-2024 to ensure that revenues are in line with spend and eliminate the need for a tax gross-up. The revenue requirements were then calculated by adding Revenue Fees and Uncollectibles (RF&U) to these annual average amounts.

2 For more details, please refer to PG&E Prepared Testimony, Chapter 3, Section C, "NRC Regulations Limit Access to NDTs Pre-Shutdown."

TABLE 11-2
DIABLO CANYON POWER PLANT PRE-SHUTDOWN PLANNING ACTIVITIES
ESCALATED TO NOMINAL DOLLARS
(THOUSANDS OF DOLLARS)

Line No.		Pre-2018	2018	2019	2020	2021	2022	2023	2024	Total
1	$(2017) Spend	$7,368	$21,568	$16,526	$21,840	$26,368	$22,928	$32,020	$39,231	$187,848
2	Nominal Spend	$7,368	$21,678	$17,563	$23,936	$29,713	$26,807	$38,529	$48,529	$214,124
3	Less 3% Trust Withdrawal	$(7,368)	$(21,678)	$(8,154)	–	–	–	–	–	$(37,200)
4	Nominal Spend To Be Recovered From Diablo Canyon Decommissioning Balancing Account (DCDBA) (before applying RF&U factor)									$176,924
5	Net Spend 2019-2022	–	–	$9,409	$23,936	$29,713	$26,807	–	–	$89,865
6	Annual Average 2020-2022	–	–	–	$29,955	$29,955	$29,955	–	–	$89,865
7	Spend 2023-2024	–	–	–	–	–	–	$38,529	$48,529	$87,058
8	Annual Average 2023-2024	–	–	–	–	–	–	$43,529	$43,529	$87,058
9	RF&U	–	–	–	$340	$340	$340	$494	$494	$2,008
10	Revenue Requirements	–	–	–	$30,295	$30,295	$30,295	$44,023	$44,023	$178,932
11	Total Revenue Requirements To Be Recovered From DCDBA									$178,932

PG&E applied a RF&U expense factor of 0.011349 (electric) to the planning activities expense forecast to calculate the annual revenue requirements. This RF&U factor was determined using the methodology adopted in PG&E's 2017 General Rate Case (GRC) D.17-05-013,[3] as approved for 2019 in AL 4020-G/5389-E, using the latest available data for the year 2019.

The revenue requirement of $178.932 million to fund DCPP planning activities occurring from 2019 through 2024 will be recovered separately from the contributions to the NDT through an expense-only balancing account, the DCDBA.[4] Upon Commission approval, PG&E proposes to transfer the balance in the Diablo Canyon Decommissioning Planning Memorandum Account, which is pending before the Commission in Application 18-07-013, to the DCDBA. This balancing account will track actual expenditures incurred, compared to the adopted DCPP pre-shutdown decommissioning planning costs.

PG&E proposes that the revenue requirement associated with the DCPP pre-shutdown decommissioning planning activities be collected from customers

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[3] 2017 PG&E GRC D.17-05-013, Section 4.1.5.7., p. 94.

[4] In the event that the Nuclear Regulatory Commission approves PG&E's exemption request to withdraw more than 3 percent annually from the NDT (PG&E Prepared Testimony, Chapter 3, Attachment A), PG&E will adjust the NDT contribution and revenue requirements accordingly.

through the ND non-bypassable charge. The Nuclear Decommissioning Adjustment Mechanism (NDAM), as authorized in D.99-10-057, will be used to record each authorized revenue requirement and the associated billed revenues. Interest will be calculated in the account on a monthly basis, based on 3-month commercial paper interest rates. Cost recovery of decommissioning planning activities revenue requirements will commence in conjunction with the next electric rate change after the effective date of the final decision in this proceeding. Annually thereafter, the under- or over-collections would be recovered or refunded through the Annual Electric True-Up (AET).[5]

At this time, PG&E is requesting cost recovery for an annual revenue requirement of $30.295 million over the period 2020-2022 and an annual revenue requirement of $44.023 million over the period 2023-2024 in order to fund the planning activities that will occur from 2019 to 2024.

D. DCPP Units 1 and 2 and HBPP Unit 3 NDT Contribution Revenue Requirements

The NDT contribution revenue requirements include the costs to decommission DCPP and HBPP. As described in Chapter 10, the appropriate level of contributions to the DCPP qualified Trust is $226.715 million for Unit 1, and $151.141 million for Unit 2, and the appropriate level of contributions to the HBPP qualified Trust is $3.791 million. PG&E will make these contributions to the Trust each quarter beginning in 2020.

PG&E applied a RF&U revenue factor of 0.011221 (electric) to the Trust contributions to calculate the Trust contribution revenue requirement. Similar to the aforementioned RF&U expense factor, this RF&U revenue factor was determined using the methodology adopted in PG&E's 2017 GRC Decision

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5 The proposed ratemaking for funding DCPP pre-shutdown planning activities represents the lowest cost and is in the best interest of ratepayers. In the event that the Commission rejects PG&E's proposal to establish the DCDBA, PG&E will continue to perform the pre-shutdown activities, as it is the reasonable and prudent course of action. In this case, the costs of the DCPP pre-shutdown activities will be funded with working capital from shareholders at a cost of $40.2 million more to ratepayers over the period 2020-2024. In the event that the Commission delays the NDCTP decision beyond December 31, 2019, the costs of the DCPP pre-shutdown activities will be funded with working capital from shareholders during the interim period until a decision is issued and rate recovery commences.

(D.17-05-013), as approved for 2019 in AL 4020-G/5389-E, using the latest available data for the year 2019.

Consistent with the prior 2015 NDCTP filing, working cash requirements are included in the calculation of the rate base on which PG&E earns a return. To calculate working cash estimates for the ND cost category, PG&E applied the appropriate working cash factors and methods authorized in the 2017 GRC to the Trust contribution estimates presented in this application. The primary working cash item that pertains to DCPP and HBPP ND is the lead-lag study. Specifically, this is the working cash capital requirement that results from the lag in payments to the NDT.

PG&E also proposes to use the return on rate base from the most recently approved Cost of Capital (COC) proceeding, the 2018 authorized COC decision (D.17-07-005).[6] This is consistent with the method that PG&E used in prior NDCTP applications.

E. NDT Contribution Revenue Requirements Cost Recovery Proposal

PG&E proposes that the revenue requirement associated with NDT contributions continue to be collected through a ND non-bypassable charge as specified in Public Utilities Code Section 379. The NDAM will be used to record each authorized revenue requirement and the associated billed revenues on a monthly basis. Interest will be calculated in the account on a monthly basis, based on 3-month commercial paper interest rates. The annual amount that PG&E proposes to recover in rates will consist of the revenue requirement and the NDAM account balance as of the end of the prior year. Cost recovery will occur through the NDAM and will be initially recovered through the next electric rate change after the effective date of the final decision in this proceeding. Annually thereafter, any under- or over-collections will be recovered or refunded through the AET. PG&E proposes to continue using the revenue allocation and rate design methodology approved in prior NDCTPs.

F. Conclusion

PG&E requests the Commission to adopt PG&E's estimated revenue requirements needed to support PG&E's NDT contributions and the costs of DCPP pre-shutdown decommissioning planning activities, beginning January 1,

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[6] AL 3887-G/5148-E, approved on October 26, 2017, established debt rates.

2020. PG&E proposes the revenue requirements establishing the final cost recovery to be finalized in a true-up AL and preliminary statement request following the final decision for this proceeding, and calculated using the same Results of Operations assumptions presented here, updated as appropriate for the COC, RF&U, and tax parameters, as adopted in PG&E's future COC, GRC and other relevant decisions.

G. Tables

TABLE 11-3
DIABLO CANYON POWER PLANT DECOMMISSIONING PLANNING ACTIVITIES REVENUE REQUIREMENT FORECAST
2020-2024
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2020	2021	2022	2023	2024	Total
1	DCPP Pre-shutdown Decommissioning Planning Activities Costs	$29,955	$29,955	$29,955	$43,529	$43,529	$176,924
2	RF&U	340	340	340	494	494	2,008
3	Requested Revenue	$30,295	$30,295	$30,295	$44,023	$44,023	$178,932

TABLE 11-4
ANNUAL NUCLEAR DECOMMISSIONING TRUST CONTRIBUTION REVENUE REQUIREMENT
BEGINNING JANUARY 1, 2020
(THOUSANDS OF NOMINAL DOLLARS)

Line No.		
1	Adopted Revenues	$67,787
2	Plus Difference	319,795
3	Requested Revenue	$387,582
4	Operating Expenses	
5	Energy Costs	–
6	Other Production	–
7	Storage	–
8	Transmission	–
9	Distribution	–
10	Customer Accounts	–
11	Uncollectibles	$1,312
12	Customer Services	–
13	Administrative and General	–
14	Franchise & SFGR Tax Requirement	3,027
15	Project Amortization	–
16	Wage Change Impacts	–
17	Other Price Change Impacts	–
18	Other Adjustments	–
19	Subtotal Expenses	$4,339
20	Taxes	
21	Superfund	–
22	Property	–
23	Payroll	–
24	Business	–
25	Other	–
26	State Corporation Franchise	$108
27	Federal Income	234
28	Total Taxes	$342
29	Depreciation	–
30	Fossil Decommissioning	–
31	Nuclear Decommissioning	$381,647
32	Total Operating Expenses	$386,328
33	Net for Return	$1,254
34	Rate Base	$16,307
35	Rate of Return	
36	On Rate Base	7.69%
37	On Equity	10.25%

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WILLIAM H. BARLEY

Q 1 Please state your name and business address.

A 1 My name is William H. Barley, and my business address is Pacific Gas and Electric Company, Humboldt Bay Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am responsible for the Site Closure Group which includes, the License Termination Plan, Final Status Surveys, site training, and Nuclear Regulatory Commission interface for license termination.

Q 3 Please summarize your educational and professional background.

A 3 I have 40 years of experience in nuclear power with 20 years of that experience being nuclear decommissioning experience in Nuclear Regulatory Commission (NRC), Department of Energy and United Kingdom facilities. In the past I have held positions of Radiation Protection Manager and Quality Manager at large boiling water reactors. I have a Bachelor of Science degree in Chemical Engineering from Penn State University and am a Certified Health Physicist by the American Board of Health Physics. Additionally, I was a past licensed Senior Reactor Operator Engineer and an NRC Inspector at TMI-2 during accident recovery.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 9, "Humboldt Bay Power Plant Completed Project Reasonableness Review Testimony"; and
- Workpapers supporting Chapter 9, "Humboldt Bay Power Plant Completed Project Reasonableness Review Testimony."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY.
STATEMENT OF QUALIFICATIONS OF ERIC D. BRACKEEN

Q 1 Please state your name and business address.

A 1 My name is Eric D. Brackeen, and my business address is Pacific Gas and Electric Company, 4111 Broad Street, Suite 120, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a manager within the Nuclear Steam Supply System and Balance of Plant Decommissioning Engineering Department, and am responsible for the reactor pressure vessel and internals segmentation and disposal aspects of decommissioning the Diablo Canyon Power Plant (DCPP).

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, San Luis Obispo in 2004. I have a total of 14 years experience in the areas of licensing, engineering, operation, maintenance, and decommissioning of the DCPP. During this time, my primary role was as system engineer responsible for the reactor coolant systems and aging management of the reactor pressure vessels and internals. In addition, I have served as a sitting member on various industry technical advisory committees responsible for resolution of materials degradation issues impacting operation and reliability of reactor internals components within the domestic and foreign fleets of pressurized water reactors.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E’s 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 4, Attachment A, “Diablo Canyon Power Plant Detailed Cost Estimate”:
  - Section E, 5.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY.
STATEMENT OF QUALIFICATIONS OF ELIZABETH (LIZ) CHAN

Q 1 Please state your name and business address.

A 1 My name is Elizabeth (Liz) Chan, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Regulatory Analyst in PG&E's Financial Forecasting and Revenue Requirements Department, within the Controller organization. I am responsible for financial analysis and modeling, including the development of Results of Operations (RO) models for incremental cost recovery filings and developing related testimony.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Environmental Economics and Policy from University of California, Berkeley in 2012. From 2012-2013, I provided analysis and decision support for various energy policy initiatives as a City Hall Fellow in the Power Enterprise Department of the San Francisco Public Utilities Commission. In August 2013, I joined PG&E as a Business Finance Associate Analyst. From 2013-2014, I provided financial planning, forecasting, and budgeting support to PG&E's Emergency Program leadership. From 2014-2016, I worked as a Business Finance Analyst in the Enterprise Planning & Governance group, and performed financial planning, reporting, and analysis to inform leadership decision-making. From 2016-2018, I worked as a Revenue Requirements Analyst, supporting major regulatory cases as a Witness Assistant, and performed numerous ad hoc financial analyses in support of regulatory strategy and commitments. In March 2018, I started my current position as a Senior Regulatory Analyst, where I am responsible for RO Witness assignments related to our incremental regulatory cases.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 11, “Trust Contribution and Planning Activities Revenue Requirements”; and
- Workpapers supporting Chapter 11, “Trust Contribution and Planning Activities Revenue Requirements.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JON FRANKE

Q 1 Please state your name and business address.

A 1 My name is Jon Franke, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Vice President (VP) of Safety Health and Claims and the Chief Safety Officer for PG&E. I also have overall responsibility for the activities associated with the decommissioning of Humboldt Bay Power Plant Unit 3, and the overall planning and cost estimating for Diablo Canyon Power Plant Units 1 and 2.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from the United States (U.S.) Naval Academy, a Master of Science degree in Mechanical Engineering from the University of Maryland, and a Master's degree in Business Administration from the University of North Carolina at Wilmington. I have over 30 years of nuclear industry experience, obtained while working in increasing levels of responsibility in the U.S. Navy, and at: Carolina Power and Light, Progress Energy, Duke Energy, and Talen Energy. I served in several leadership positions at Brunswick Nuclear Plant before becoming the Plant General Manager, and later VP, at Crystal River Nuclear Plant. Prior to joining PG&E in 2017, I served as VP of Susquehanna Nuclear Plant, where I was responsible for all aspects of safe, reliable, and efficient nuclear plant operation, design, and maintenance. Immediately prior to my current assignment as the VP of Safety Health and Claims, I was the VP of Power Generation for PG&E.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2018 Nuclear Decommissioning Triennial Cost Proceeding:

- Chapter 1, "Introduction and Policy."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TED HUNTLEY

Q 1 Please state your name and business address.

A 1 My name is Ted Huntley, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E or the Company).

A 2 I am the Director of the Investments and Benefit Finance Department at PG&E, where I and my department are responsible for the oversight of all employee benefit investments sponsored by PG&E Corporation and its affiliates, including the Company. In addition, my department is responsible for oversight of the PG&E's Nuclear Decommissioning Trust Investments. Investments and Benefit Finance serves two committees in the discharge of its duties: the PG&E Corporation Employee Benefit Committee, and PG&E's Nuclear Facilities Decommissioning Master Trust Committee. My department provides advice and recommendations to these committees on a broad range of issues concerning asset allocation, asset class structure, and investment management, as well as contribution strategy.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Industrial Engineering from the Pennsylvania State University in 1987, and a Master of Science degree in Industrial Engineering from Stanford University in 1991.

I began my employment with PG&E in 1991. Between 1991 and 1994, I was a Resource Planning Engineer in the Electric Resources Planning Department. In 1994, I moved to the Finance organization, where I held various positions in Financial Planning and Analysis and Treasury, including Manager of Financing. I joined the Investments and Benefit Finance Department in 2007 and was named Director of the department in 2013.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Triennial Cost Proceeding:

- Chapter 10, "Contributions Funding the Nuclear Decommissioning Trust"; and

- Workpapers supporting Chapter 10, “Contributions Funding the Nuclear Decommissioning Trust.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF THOMAS P. JONES

Q 1 Please state your name and business address.

A 1 My name is Thomas P. Jones, and my business address is Pacific Gas and Electric Company, 735 Tank Farm Road, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E or the Utility).

A 2 I am the Director of Strategic Initiatives at Diablo Canyon Power Plant (DCPP), where I oversee the license renewal projects for DCPP, dry cask storage licenses at both Humboldt Bay Power Plant and DCPP, the DCPP Land Stewardship Program, and other intiatives related to DCPP.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Arts degree in Political Science from the University of California, Santa Barbara, and have been actively engaged in California public policy since 1994. I worked for the California State Legislature for seven years, covering matters related to: utilities, unitary tax, public education, and emergency preparedness, including nuclear-related legislation and DCPP property tax impacts associated with rapid depreciation related to the proposed electrical de-regulation in 1997-1998.

I joined PG&E's Government Relations Department in 2001. In my various capacities at PG&E, I have received extensive training in emergency planning from the Utility, the Nuclear Energy Institute, and the Harvard School of Public Health, and have served on the emergency response organization for 15 years. I have also served on various economic-development community boards, including the Economic Vitalty Corporation in San Luis Obispo, for nearly a decade.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2018 Nuclear Decommissioning Triennial Cost Proceeding:

- Chapter 3, "Diablo Canyon Power Plant Decommissioning Planning Activities":
  - Section E. 2.;

- Portions of the Chapter 4, Attachment A, “Diablo Canyon Power Plant Detailed Cost Estimate”; and
- Chapter 5, “Diablo Canyon Power Plant Lands and Related Matters.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BRIAN KETELSEN

Q 1 Please state your name and business address.

A 1 My name is Brian Ketelsen, and my business address is Pacific Gas and Electric Company, 4111 Broad Street San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Manager of Project Controls for Diablo Canyon Power Plant (DCPP) Decommissioning overseeing financial analytics, schedule development, execution of projects, and contract management. In addition, my team is the decommissioning liaison between corporate finance, project governance, and regulatory proceedings.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts in Economics from San Diego University. I joined PG&E in 2011 after financial analyst roles for both Wells Fargo Bank and Cable Audit Associates. Since joining PG&E, I have worked up through and ultimately supervised the project finance organization at DCPP. Our team facilitated the project approval, controls, governance, and closeout process for all projects at DCPP. I have developed and maintained multiple project management tools to improve long term financial planning, funding authorization, and risk management. I joined DCPP decommissioning in 2018 and have overseen the development of the decommissioning cost estimate, schedule, and the associated filing. I also supported testimony and workpapers for the 2014-2017 General Rate Cases and contributed to the HBPP Decommissioning team during the 2015 Nuclear Decommissioning Cost Triennial Proceeding.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Portions of the Chapter 4, "Diablo Canyon Power Plant Detailed Cost Estimate"; and
- Chapter 7, "Diablo Canyon Power Plant Completed Project Reasonableness Review."

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ERIC NELSON

Q 1 Please state your name and business address.

A 1 My name is Eric Nelson, and my business address is Pacific Gas and Electric Company, 4111 Broad Street, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of Diablo Canyon Decommissioning Projects. I am responsible for the planning and cost estimating for Diablo Canyon Power Plant units 1 and 2.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering, Master's in Business Administration, Professional Engineer in Mechanical Engineering California, and Project Management Professional certification. I have a total of 33 years of experience in the areas of engineering, maintenance, project management, and decommissioning.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 2, "Diablo Canyon Power Plant Preliminary Decommissioning Preparation";
- Chapter 3, "Diablo Canyon Power Plant Decommissioning Planning Activities";
- Chapter 4, "Diablo Canyon Power Plant Site-Specific Decommissioning Cost Estimate";
- Portions of the Chapter 4, Attachment A, "Diablo Canyon Power Plant Detailed Cost Estimate"; and
- Chapter 7, "Diablo Canyon Power Plant Completed Project Reasonableness Review."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TREVOR D. REBEL

Q 1 Please state your name and business address.

A 1 My name is Trevor D. Rebel, and my business address is Pacific Gas and Electric Company, 4111 Broad Street, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Decommissioning Environmental Supervisor and I am responsible for coordinating the historical site assessment for radiological and non-radiological contamination. Additionally, responsible for planning and executing the site characterization plan for both radiological and non-radiological contamination.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Soil Science from California Polytechnic University in 1997. I have worked for PG&E since 1997 in the Operations Services Department holding roles as an Operator, Chemistry and Radiation Protection Technician, Chemistry Laboratory Supervisor, Environmental Coordinator, and Senior Chemistry Engineer. Prior to working for PG&E, I served for nine years in the United States Naval Nuclear Power Program.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 2, "Diablo Canyon Power Plant Preliminary Decommissioning Preparation":
  - Section D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BRENT RITTMER

Q 1 Please state your name and business address.

A 1 My name is Brent Rittmer, and my business address is Anata Management Solutions, 9301 South 6090 West, West Jordan, Utah.

Q 2 Briefly describe your responsibilities at Anata Management Solutions.

A 2 I am a Security Consultant for Anata Management Solutions.

Q 3 Please summarize your educational and professional background.

A 3 I have over 30 years of experience in security positions at commercial nuclear power plants. I work at Quad Cities Nuclear Power Station for 18 years starting as a Security Scheduler and then as the Security Operations Manager. Afterwards, I worked at Turkey Point Nuclear Plant as a Security Shift Supervisor and Site Security Manager before securing employment at Pacific Gas & Electric Company (PG&E). In 2012, I joined PG&E as a Security Programs Manager at Diablo Canyon Power Plant. From 2014 to 2018, I was the Independent Spent Fuel Storage Installation Manager at Humboldt Bay Power Plant (HBPP). HBPP was in active decommissioning during this time. I retired from PG&E in May 2018 and joined Anata Management Solutions.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 3, "Diablo Canyon Power Plant Decommissioning Activities":
  - Section G.1.; and
- Portions of the Chapter 4, Attachment A, "Diablo Canyon Power Plant Detailed Cost Estimate."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JAMES T SALMON

Q 1 Please state your name and business address.

A 1 My name is James T Salmon, and my business address is Pacific Gas and Electric Company, 1000 King Salmon Avenue, Eureka, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Deputy Director for decommissioning of the Humboldt Bay Power Plant. I am responsible for oversight of the: decommissioning contractor activities, environmental remediation activities, and site restoration activities. Additionally, I am responsible for environmental compliance and waste management activities associated with the decommissioning project.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Chemistry, and Master of Arts degree in Business Administration. I have a total of 38 years of experience in the following areas: waste management, environmental program management, and project management. I began my career as a regulator with the Illinois Environmental Protection Agency, and have worked throughout my career on projects with large volumes of chemical or radiological waste. I was part of the project team that successfully planned decommissioning for the Department of Defense Chemical weapons demilitarization sites. I was a Manager for Raytheon/Washington Group International/URS Corp. for 16 years, destroying nerve agents or blister agents, and providing leadership for plants at: Johnston Island in the South Pacific, Pueblo in Colorado, Tooele in Utah, and Shchuch'ye in Russia.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Triennial Cost Proceeding:

- Chapter 9, "Humboldt Bay Power Plant Completed Project Reasonableness Review Testimony"; and

- Workpapers supporting Chapter 9, “Humboldt Bay Power Plant Completed Project Reasonableness Review Testimony.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LOREN D. SHARP

Q 1 Please state your name and business address.

A 1 My name is Loren D. Sharp, and my business address is Pacific Gas and Electric Company, Humboldt Bay Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Senior Director of Nuclear Decommissioning for Humboldt Bay Power Plant (HBPP) and Diablo Canyon Power Plants (DCPP). I am also Nuclear Plant Manager of the HBPP Unit 3. I am responsible for all activities associated with the decommissioning of HBPP Unit 3. In addition, I am responsible for the overall planning and cost estimating for DCPP Units 1 and 2.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Nuclear Engineering, Master of Science degree in Nuclear Engineering, Professional Engineer in Mechanical Engineering, and Senior Reactor Operator certification. I have a total of 47 years of experience with expertise in the following areas: engineering design; plant operation; plant management; project management; and plant decommissioning/demolition.

I was hired by PG&E based on my plant management and project management expertise to complete nuclear fuel assembly loading into storage casks at HBPP. In addition, I was hired to provide leadership for decommissioning the HBPP site, as well as expertise to support filing for future DCPP decommissioning phase. I had been part of the management team that successfully designed for decommissioning for the Department of Defense Chemical weapons de-militarization sites. I was a Vice President/Plant General Manager for Raytheon/Washington Group International for 10 years, destroying nerve agents or blister agents, and providing senior leadership for plants at: Johnston Island in the South Pacific; Umatilla in Oregon’ Pueblo in Colorado; Blue Grass in Kentucky; and Tirana in Albania.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2018 Nuclear Decommissioning Triennial Cost Proceeding:

- Chapter 4, "Diablo Canyon Power Plant Site-Specific Decommissioning Cost Estimate":
  - Section E:
    - Section 6;
- Chapter 8, "Humboldt Bay Power Plant Unit 3 Updated Nuclear Decommissioning Cost Estimate":
  - Attachment A, "Humboldt Bay Power Plant Unit 3 Decommissioning Cost Estimate"; and
  - Attachment B, "2016 Humboldt Bay Power Plant Unit 3 Decommissioning Project Report"; and
- Chapter 9, "Humboldt Bay Power Plant Completed Project Reasonableness Review Testimony":
  - Attachment A, "Humboldt Bay Power Plant Unit 3 Completed Projects Review"; and
  - Attachment B, "Humboldt Bay Power Plant Unit 3 Decommissioning Pictorial Summary."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF PHILIPPE R. SOENEN

Q 1 Please state your name and business address.

A 1 My name is Philippe R. Soenen, and my business address is Pacific Gas and Electric Company, 4111 Broad Street, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Decommissioning Environmental and Licensing Manager, and am responsible for obtaining permits associated with the Diablo Canyon (DC) site, decommissioning licensing activities for both Humboldt Bay Power Plant and Diablo Canyon Power Plant (DCPP), and license renewal applications for both Humboldt Bay (HB) and DC Independent Spent Fuel Storage Installation (ISFSI).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from the University of California, San Diego, in 2002.

Prior to joining PG&E in 2004, I was a Project Engineer Contractor supporting the DC ISFSI and HB ISFSI application projects. Prior to assuming my present position at PG&E, I have held positions, including: Assistant Project Manager for the DCPP license renewal application, DCPP Licensing Supervisor, and project manager for the HB ISFSI license renewal application.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2018 Nuclear Decommissioning Triennial Cost Proceeding:

- Chapter 2, "Diablo Canyon Power Plant Preliminary Decommissioning Preparation":
  - Section D;
- Chapter 4, "Diablo Canyon Power Plant Site-Specific Decommissioning Cost Estimate":
  - Section E:
    - Subsection E.3.g.2;

- Chapter 5, “Diablo Canyon Power Plant Lands and Related Matters”:
  - Section G; and
- Chapter 6, “Spent Nuclear Fuel.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ERIK M. WERNER

Q 1 Please state your name and business address.

A 1 My name is Erik M. Werner, and my business address is Pacific Gas and Electric Company, 4111 Broad Street, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Manager in the Strategic Decommissioning Planning Department and I am responsible for the systems & area closure aspects of decommissioning Diablo Canyon Power Plant (DCPP).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from the California Polytechnic State University of San Luis Obispo in 2000. Following graduation, I became employed by PG&E at DCPP in the Engineering Department. In 2003, I transferred to the DCPP Plant Operations Department and was licensed in 2005 by the Nuclear Regulatory Commission (NRC) to operate DCPP units 1 and 2 as a Senior Reactor Operator. I was responsible for oversight of on-shift, DCPP control room operations through mid-2014. Following my time in the control room I led the DCPP training programs as Nuclear Operations Training Manager, responsible for training and qualification of all Operations Department employees, including oversight and administration of the Operator requalification and initial NRC license programs. I joined the Strategic Decommissioning Planning Department in early 2017.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 4, "Diablo Canyon Power Plant Site-Specific Decommissioning Cost Estimate."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAN WILLIAMSON

Q 1 Please state your name and business address.

A 1 My name is Dan Williamson, and my business address is G4S Special Tactical Services, 1395 University Boulevard, Juniper, Florida.

Q 2 Briefly describe your responsibilities at G4S Special Tactical Services.

A 2 I am a Director, Special Tactical Services, where I work with commercial nuclear plants in many areas including Force-on-Force (FOF) testing of nuclear plant security strategies, protective strategy review, design and evaluation, efficiency analysis to reduce responder staffing, vulnerability assessments, exploitability analysis and barrier plan design review.

Q 3 Please summarize your educational and professional background.

A 3 I have 18 years of experience with physical security systems, equipment and procedures. I served in a leading role in 82 FOF exercises and was a Team Leader for the Nuclear Industry's 17-man National Composite Adversary Force. I have experience writing drill scenarios and event matrices for Xcel Energy Fleet and Cooper Nuclear Station. I am a member of the Nuclear Energy Institute's FOF Task Force where I helped identify and resolve industry issues regarding FOF. I am a qualified AVERT software operator and assisted ARES Corporation develop the software for nuclear-specific design basis threat adversary and security force response.

Prior to this, I held the following positions; United States Marine, Armed Security Officer, Security Training Instructor and Security Shift Field Supervisor.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Chapter 3, "Diablo Canyon Power Plant Decommissioning Planning Activities";
  - Section G.1.; and
- Portions of the Chapter 4, Attachment A, "Diablo Canyon Power Plant Detailed Cost Estimate."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KRISTIN M. ZAITZ

Q 1 Please state your name and business address.

A 1 My name is Kristin M. Zaitz, and my business address is Pacific Gas and Electric Company, 4111 Broad Street San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am an Engineering Manager responsible for decommissioning civil and systems engineering. I am responsible for building demolition, site infrastructure, and plant water system aspects of decommissioning Diablo Canyon Power Plant (DCPP). I am responsible for engineering management of the active decommissioning at Humboldt Bay Power Plant (HBPP) Unit 3.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Science in Civil Engineering from Cal Poly, San Luis Obispo in 2003. I am a Licensed Professional Civil Engineer in the state of California. I earned my Project Management Professional certification in 2009. I joined PG&E in 2001 and served in various capacities at DCPP, including civil engineering, construction planning, and major plant projects. I have been involved in various aspects of HBPP decommissioning since 2013.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2018 Nuclear Decommissioning Cost Triennial Proceeding:

- Portions of the Chapter 4 Attachment A, "Diablo Canyon Power Plant Detailed Cost Estimate."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.