Document P01-1421-002, Rev 0

DECOMMISSIONING COST STUDY

for the

HUMBOLDT BAY POWER PLANT UNIT 3

2006 SAFSTOR

prepared for

PACIFIC GAS & ELECTRIC COMPANY

prepared by

TLG Services, Inc.
Bridgewater, Connecticut

February 2002

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Rev. No.	CRA No.	Date	Item Revised	Reason for Revision
0		02/13/02		Original Issue

EXECUTIVE SUMMARY

TLG Services, Inc (TLG) has prepared a site-specific cost study for the 2006 SAFSTOR decommissioning of the Humboldt Bay Power Plant Unit 3 (HBPP3) for the Pacific Gas and Electric Company (PG&E). This estimate includes a comprehensive cost and schedule estimate for completing the decommissioning of HBPP3 based on outlined work areas of the plant. Manpower levels and activity durations were developed and are reflected within the project schedule along with other associated site programs. The projected cost to decommission HBPP3, including a 21% contingency, is estimated to be approximately $300.4 million (2002 dollars). The California Public Utility Commission has previously ruled that certain costs that were incurred after HBPP3 was permanently shutdown would not be included in rates for recovery of decommissioning costs. The portion of the above costs that have been identified by the (CPUC) as decommissioning disallowances is estimated at $712,869. The major cost contributors to the overall decommissioning cost are labor, spent fuel storage and the disposition of waste generated in the decontamination and demolition of the unit. The estimate is based on several key assumptions, including regulatory requirements, estimating methodology, contingency requirements, low-level radioactive waste disposal availability, high-level radioactive waste disposal options, and site restoration requirements. A complete discussion of the assumptions used in this estimate is presented in Section 3.

A detailed breakdown of these major cost contributors to the decommissioning cost estimate is reported in Section 6 of this document. Schedules of annual expenditures are provided in Section 3, and detailed cost, waste volume, and man-hour schedules are provided in Appendix D. Costs are reported in 2002 dollars. Cash flows are based on schedule forecasts as of July 2001. The estimate includes the costs for storing the HBPP3 spent fuel until such time that the Department of Energy (DOE) can complete the transfer to an off-site facility.

Alternatives and Regulations

The Nuclear Regulatory Commission (NRC) provided general decommissioning guidance in the rule adopted on June 27, 1988.[1] In this rule the NRC sets forth technical and financial criteria for decommissioning licensed nuclear facilities. The regulation addresses planning needs, timing, funding methods, and environmental review requirements for decommissioning. The rule also defined three

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1 U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72 "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (p 24018+), June 27, 1988.

decommissioning alternatives as being acceptable to the NRC — DECON, SAFSTOR and ENTOMB.

> DECON was defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." [2]
>
> SAFSTOR was defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." [3]
>
> ENTOMB was defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactive material decays to a level permitting unrestricted release of the property." [4]

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The amendments allow for greater public participation and better define the transition process from operations to decommissioning. The costs and schedules presented in this estimate follow the general guidance and sequence in the amended regulations.

Methodology

The methodology used to develop the decommissioning cost estimates for HBPP3 follows the basic approach originally presented in the Guidelines.[5] This reference describes a unit cost factor method for estimating decommissioning activity costs. The unit cost factors used in this study reflect site-specific costs, as well as the latest available information about worker productivity in decommissioning. The data obtained from the Shippingport Station Decommissioning Project, completed in 1989,

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2 Ibid. Page FR24022, Column 3.
3 Ibid.
4 Ibid. Page FR24023, Column 2.
5 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

as well as from TLG's involvement in the decommissioning planning and engineering for the Shoreham, Yankee Rowe, Trojan, Rancho Seco, Pathfinder, and Cintichem reactor facilities, is reflected within this estimate.

An activity duration critical path is used to determine the total decommissioning program schedule required for calculating the carrying costs which include program management, administration, field engineering, equipment rental, quality assurance, and security. This systematic approach for assembling decommissioning estimates has ensured a high degree of confidence in the reliability of the resulting costs.

This study assumes that PG&E's primary contractor is already experienced in the techniques and technology of nuclear power plant decommissioning, and therefore performs all work (both field activities and project management) in an optimally efficient manner. Therefore, this study does not attempt to quantify any cost impact for any increase in efficiency from experience gained in decommissioning other plants in the past.

<u>Contingency</u>

Consistent with industry practice, contingencies are applied to the decontamination and dismantling costs developed as, "specific provision for unforeseeable elements of cost within the defined project scope, particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur."[6] The cost elements in this estimate are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in this estimate, does not account for price escalation and inflation in the cost of decommissioning during the decommissioning period.

The use and role of contingency within decommissioning estimates is not a safety factor issue. Safety factors provide additional security and address situations that may never occur. Contingency funds, by contrast, are expected to be fully expended throughout the program. Application of contingency on a line-item basis is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks.

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6 Project and Cost Engineers' Handbook, Second Edition, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, p. 239.

Low-Level Radioactive Waste Disposal

The contaminated and activated material removed in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level radioactive waste, although not all of the material is suitable for "shallow-land" disposal. Much of the contaminated material generated in dismantling the plant is routed off-site to waste recovery vendors for processing, decontamination and volume reduction.

With the passage of the "Low-Level Radioactive Waste Disposal Act" in 1980, and its Amendments of 1985, the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders. However, at this time a regional facility is not available. There are 3 types of low-level radioactive waste acceptable for near surface disposal, Class A, B, and C. All require controlled disposal in a licensed disposal facility. These classes distinguish the degree of disposal requirements with A having the least and C the greatest requirements. For the purposes of this estimate, Class A low-level radioactive waste generated in the decontamination and dismantling of HBPP3, is assumed to be shipped outside the Southwest Compact to the Envirocare facility, in Clive, Utah. Class B and C low-level radioactive waste is designated for disposal at the future Southwest Compact disposal site or other nationally available Class B/C low-level disposal site neither of which currently exists. It is assumed for this estimate that one of these alternatives becomes available by 2005 to support decommissioning operations.

High-Level Waste

Congress passed the "Nuclear Waste Policy Act" in 1982, assigning the responsibility for disposal of spent nuclear fuel created by the commercial nuclear generating plants to the Department of Energy (DOE). This legislation also created a Nuclear Waste Fund to cover the cost of the program, which is funded by the sale of electricity from PG&E and an estimated equivalent for assemblies irradiated prior to April 1983. The target date for startup of the federal Waste Management System was originally 1998. However, after a series of delays, the DOE has no plans to accept any spent fuel from commercial U.S. reactors before the year 2010.

For purposes of this cost study, TLG has assumed that the high-level waste repository or some interim storage facility will be operational by 2010. Under the provisions of 10 CFR 50.54(bb), PG&E is responsible for the management of the irradiated nuclear fuel at the reactor until such time that possession of the fuel is transferred to the Secretary of Energy. As such, this estimate includes the continuing cost to store the fuel until the transfer can be completed.

Site Restoration

The efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below the NRC guidelines will result in substantial damage to many of the site structures. Blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially damage power block structures, potentially weakening the footings and structural supports. Prompt demolition is clearly the most appropriate and cost-effective option.

All above-ground demolition debris is assumed to be transported and disposed of at a controlled disposal facility. Site structures not associated with Units 1 and 2 will be removed to a nominal depth of three feet below grade level. Below grade structures will be decontaminated and backfilled with clean fill. The site will then be graded and landscaped.

1. INTRODUCTION

TLG prepared this decommissioning cost estimate to provide Pacific Gas and Electric Company (PG&E) with sufficient information to prepare the financial planning documents for decommissioning, as required by the Nuclear Regulatory Commission (NRC). It is not a detailed engineering document, but a cost estimate prepared in advance of the detailed engineering planning required to carry out the decommissioning of the HBPP3.

1.1 OBJECTIVE OF STUDY

The objective of the study is to prepare a comprehensive estimate of the cost, a schedule of the associated activities, and an estimate of the volume of radioactive waste generated during decommissioning of HBPP3.

1.2 SITE DESCRIPTION

HBPP3 is located approximately four miles southwest of Eureka, California. The site consists of approximately 143 acres located on the mainland shore of Humboldt Bay. Figure 1.1 shows the layout of the site and the surrounding area. The adjacent generating units are fossil-fueled and are not considered in the scope of this study, except where noted.

The Nuclear Steam Supply System (NSSS) for HBPP3 consists of a single cycle, natural circulation, boiling water reactor and the associated control and support systems. Figure 1.2 shows a schematic diagram of the reactor pressure vessel and internal components. The generating unit has a rated core thermal power of 220 MWth (thermal) with a corresponding net electrical output of 65 MWe (electric).

The NSSS is located within the "primary containment structure." The primary containment is located mostly below grade and consists of a drywell vessel and a suppression chamber. Both the drywell and the suppression chamber area are located within a reinforced concrete caisson. The drywell vessel is centrally located in the caisson and serves as the primary containment vessel. The suppression chamber is constructed of reinforced concrete and lined with carbon steel plate. Six vent pipes connect the drywell to a common ring header at the top of the suppression chamber. Downcomers drop from the ring header and terminate below the normal water level of the suppression pool. As a system, the drywell, suppression chamber, and interconnecting piping were designed to reduce the pressure increase in the event of a local process system piping failure. Figure 1.3, a sectional view through the caisson, depicts this general arrangement and the associated concrete structure.

The turbine-generator system converts heat produced in the reactor to electrical energy. This system converts the thermal energy of steam produced in the reactor vessel into mechanical shaft power and then into electrical energy. The unit's turbine-generator consists of a tandem, compound, double flow, condensing turbine directly connected to a 13,800V, 3-phase, 60 cycle, hydrogen-cooled, synchronous generator. The turbine consists of a single flow high-pressure section and a double flow, low-pressure section with a crossover pipe connecting the two sections. The turbine is operated in a closed feedwater cycle whereby steam is condensed and the condensate/feedwater is returned to the reactor vessel. Heat rejected in the main condenser is removed by the Circulating Water System (CWS). The CWS delivers the water required to remove the heat load from the main condenser and other auxiliary equipment and returns it to the bay through the discharge pipes and a canal.

Commercial operation began in August of 1963 and continued until July of 1976, at which time the unit was shut down after approximately 13 years of operation to conduct seismic modifications. In 1983 PG&E announced the decision to decommission Unit 3. The plant has been maintained in NRC safe-storage since that time. Active plant systems presently supporting the wet storage of the spent fuel will be retired once the fuel is transferred to an Independent Spent Fuel Storage Installation (ISFSI). This activity is scheduled to be completed in 2006.

1.3 REGULATORY GUIDANCE

The Nuclear Regulatory Commission (NRC or Commission) provided decommissioning guidance in the rule "General Requirements for Decommissioning Nuclear Facilities," (Ref. 1) published and adopted on June 27, 1988. This rule amended NRC regulations and established technical and financial criteria for decommissioning licensed nuclear facilities. The regulation addresses decommissioning planning needs, timing, funding methods, and environmental review requirements. The intent of the rule is to ensure that decommissioning will be accomplished in a safe and timely manner and that adequate licensee funds will be available. Subsequent to the rule, the NRC issued Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," (Ref. 2) which provided guidance to the licensees of nuclear facilities on methods acceptable to the NRC staff for complying with the requirements of the rule. The regulatory guide addresses the funding requirements and provides guidance on the content and form of the financial assurance mechanisms indicated in the rule amendments.

The rule defines the following three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR and ENTOMB.

> DECON is defined by the rule as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."
>
> SAFSTOR is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use."
>
> ENTOMB is defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactive material decays to a level permitting unrestricted release of the property."

The rule places limits on the time allowed to complete the decommissioning process. For SAFSTOR, the process is restricted in overall duration to 60 years unless it can be shown that a longer duration is necessary to protect public health and safety. The guidelines for ENTOMB are similar, providing the NRC with both sufficient leverage and flexibility to ensure that these deferred options are only used in situations where it is reasonable and consistent with the definition of decommissioning. Consequently, with these restrictions, the SAFSTOR and ENTOMB options are no longer decommissioning alternatives in themselves, as neither terminates the license for the site. At the conclusion of a 60-year dormancy period (or longer for ENTOMB if the NRC approves such a case), the site would still require significant remediation to meet the definition of unrestricted release and license termination. The 60-year restriction has limited the practicality of the ENTOMB alternative at commercial reactors that generate significant amounts of long-lived radioactive material. However, the NRC is currently re-evaluating this option and the technical requirements and regulatory actions that would be necessary for entombment to become a viable option.

When the decommissioning regulations were adopted in 1988, it was assumed that the majority of licensees would decommission at the end of the operating license life. Since that time, several licensees had permanently and prematurely ceased operations without having submitted a decommissioning plan. In addition, these licensees requested exemptions from certain operating requirements as being unnecessary once the reactor is defueled. Each case has been handled individually without clearly defined generic requirements. The NRC amended the decommissioning regulations in 1996 to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process (Ref. 3). The new amendments allow for greater public participation and better define the transition process from operations to decommissioning.

Under the revised regulations, licensees will submit written certification to the NRC within 30 days after the decision is made to cease operations. Certification will also be required once fuel has been permanently removed from the reactor vessel. Submittal of these notices will entitle the licensee to a fee reduction and eliminate the obligation to follow certain requirements needed only during operation of the reactor. Within two years of submitting notice of permanent cessation of operations, the licensee is required to submit a Post-Shutdown Decommissioning Activities Report (PSDAR) to the NRC. This report describes the planned decommissioning activities, the associated sequence and schedule, and an estimate of expected costs. Prior to completing decommissioning, the licensee will be required to submit an application to the NRC to terminate the license, along with a license termination plan.

1.3.1 Nuclear Waste Policy Act

Congress passed the Nuclear Waste Policy Act in 1982 (Ref. 4), assigning the responsibility for disposal of spent nuclear fuel from the commercial generating plants to the Department of Energy (DOE). Two permanent disposal facilities were envisioned, as well as an interim facility. To recover the cost of permanent spent fuel disposal, this legislation created a Nuclear Waste Fund through which money was to be collected from the consumers of the electricity generated by commercial nuclear power plants. The target startup date of the federal Waste Management System was 1998.

After pursuing a national site selection process, the Act was amended in 1987 to designate Yucca Mountain, Nevada, as the only site to be evaluated for geologic disposal of high-level waste. Also in 1987, DOE announced a five-year delay in the opening date for the repository, from 1998 to 2003. Two years later, in 1989, an additional 7-year delay was announced, primarily due to problems in obtaining the required permits from the state of Nevada to perform the required characterization of the site. DOE has projected additional delays as a result of proposed Congressional reductions in appropriations for the program.

The NRC recently approved the DOE siting guidelines for the Yucca Mountain site. A recommendation by the Energy Secretary to use the Yucca Mountain site as the country's high-level waste burial site has been made. Even at this point in the review process, the ultimate fate of the site is still very questionable.

Utilities have responded to this impasse by initiating legal action and constructing supplemental storage as a means of maintaining necessary operating margins. On November 14, 1997, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision in Northern States Power Company, et al., v. U.S. Department of Energy. In the decision, the Court reaffirmed its ruling in Indiana Michigan Power Company, et al v. U.S. Department of Energy that the DOE has an unconditional obligation to begin disposal of the utilities' spent nuclear fuel by January 31, 1998. Since the agency was not in default at the time the Northern States Power decision was issued, the court declined to prescribe "remedies" in the likely event the DOE failed to uphold its obligation. More recently, the U.S. Court of Federal Claims has ruled in favor of Yankee Atomic Power Company in its damage claim. However, even with the ruling, the DOE's position has remained unchanged. The agency continues to maintain that its delayed performance is unavoidable because it does not have an operational repository and does not have authority to provide storage in the interim. Consequently, the DOE has no plans to accept any spent fuel from commercial U.S. reactors before the year 2010.

For purposes of this cost study, TLG has assumed that the high-level waste repository or some interim storage facility will be operational by 2010. Under the provisions of 10 CFR 50.54(bb), PG&E is responsible for the management of the irradiated nuclear fuel at the reactor until such time that possession of the fuel is transferred to the Secretary of Energy.

As such, this estimate includes the continuing cost to store the fuel until the transfer can be completed.

For purposes of the decommissioning cost estimate, DOE is assumed to initiate spent fuel acceptance from HBPP3 starting in the year 2011. The rate of acceptance from HBPP3 is based upon the "Acceptance Priority Ranking & Annual Capacity Report" (Ref. 5) issued by the DOE's Office of Civilian Radioactive Waste Management. Based upon this publication and a 2011 start date, the transfer can be completed by the year 2015.

1.3.2 Low-Level Radioactive Waste Policy Amendments Act

Congress passed the "Low-Level Radioactive Disposal Act" in 1980, declaring the states as being ultimately responsible for the disposition of low-level radioactive waste generated within their own borders. The federal law encouraged the formation of regional groups or compacts to implement this objective safely, efficiently and economically, and set a target date of 1986. With little progress, the "Amendments Act" of 1985 (Ref. 6) extended the target date, with specific milestones and strong sanctions for non-compliance. However, more than 20 years later, no new regional sites have been developed, only one new commercial site has been placed in service, and even the most advanced program is far behind schedule.

With the passage of the "Low-Level Radioactive Waste Disposal Act" in 1980, and its Amendments of 1985, the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own boarders. However, at this time, a regional facility is not available. There are 3 types of low-level radioactive waste acceptable for near surface disposal, Class A, B, and C. All require controlled disposal in a licensed disposal facility. These classes distinguish the degree of disposal requirements with A having the least and C the greatest requirements. For the purposes of this estimate, Class A low-level radioactive waste generated in the decontamination and dismantling of HBPP3, is assumed to be shipped outside the Southwest Compact to the Envirocare Facility, in Clive Utah. Class B and C low-level radioactive waste is designated for disposal at the future Southwest Compact disposal site or at another nationally available Class B/C low-level disposal site. While neither of these alternatives currently exists, it is assumed for this estimate that one becomes available by 2005 to support decommissioning operations.

1.3.3 Other Regulations and Standards Applicable to Decommissioning

Title 10 Code of Federal Regulations Part 20 (10 CFR 20) titled, "Standards for Protection Against Radiation," regulates the receipt, possession, use, transfer, and disposal of licensed material by any licensee in such a manner that the total dose to an individual does not exceed the radiation protection standards. (According to 10 CFR 20.1001, the total dose to an individual includes doses from licensed and unlicensed radioactive material and from radiation sources other than background radiation.) In addition, the requirements of 10 CFR 20.1301 apply to NRC-licensed facilities during decommissioning and when the facility is operational.

10 CFR 50 Appendix I provides numerical guidance for keeping radioactive materials in liquid and gaseous effluents released to unrestricted areas ALARA, "As Low As Reasonably Achievable" during normal operations of a nuclear power reactor.

1.3.4 Radioactive Criteria for License Termination

In 1997, 10 CFR 20, Subpart E, "Radiological Criteria for License Termination" (Ref. 7) was published. This subpart provides radiological criteria for releasing a facility for unrestricted use. The regulation provides that the site can be released for unrestricted use if radioactivity levels are such that the average member of a critical group would not receive a Total Effective Dose Equivalent (TEDE) in excess of 25 millirem per year, and provided residual radioactivity has been reduced to levels that are ALARA.

In December 1997 the NRC, in cooperation with the EPA, DOE, and DOD issued the "Multi-Agency Radiation Survey and Site Investigation Manual" (MARSSIM) as NUREG –1575. This document provides information on planning, conducting, evaluating and documenting radiological surveys for demonstrating compliance with dose or risk-based regulations and standards. The NRC is using this manual as its primary standard for reviewing License Termination Plans.

It should be noted that the NRC and the Environmental Protection Agency (EPA) differ on the amount of residual radioactivity considered acceptable after site remediation. The EPA has two limits that apply to radioactive materials. An EPA limit of 15 millirem per year is derived from criteria established by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund). An additional limit of 4 millirem per year, as defined in 40 CFR Part 141.16, is applied to drinking water.

The Congress has prohibited the EPA from spending funds to enforce cleanup requirements at sites under the jurisdiction of the NRC. However, the mandate is not legally binding and the possibility exists that a site, once released from its NRC license, could be subject to EPA regulation. Furthermore one state has established decommissioning site release limits that are below both the EPA and NRC limits.

FIGURE 1.1

LAYOUT OF THE NUCLEAR PLANT SITE AND SURROUNDING AREA

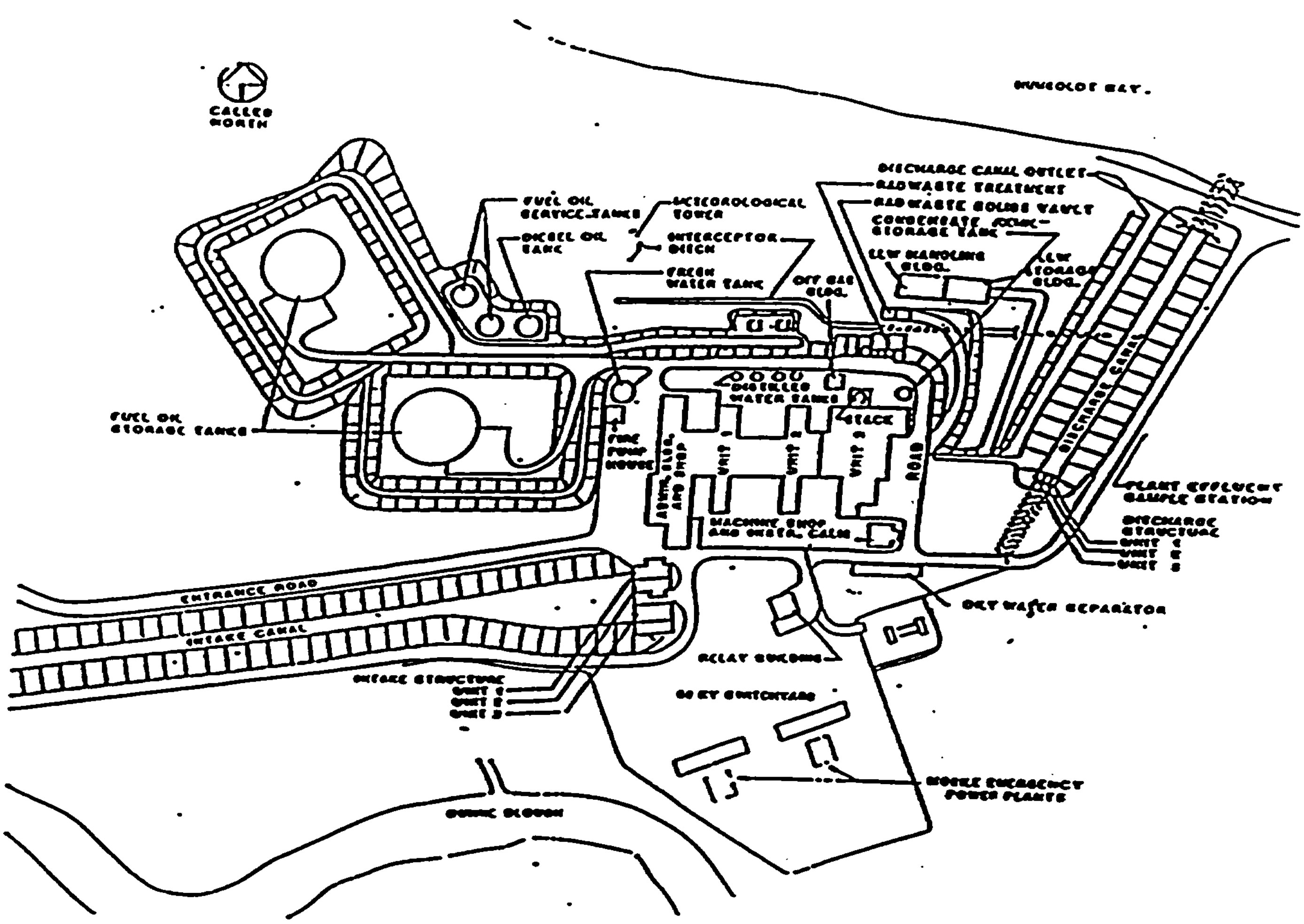


FIGURE 1.2

SCHEMATIC DIAGRAM OF THE VESSEL AND INTERNALS

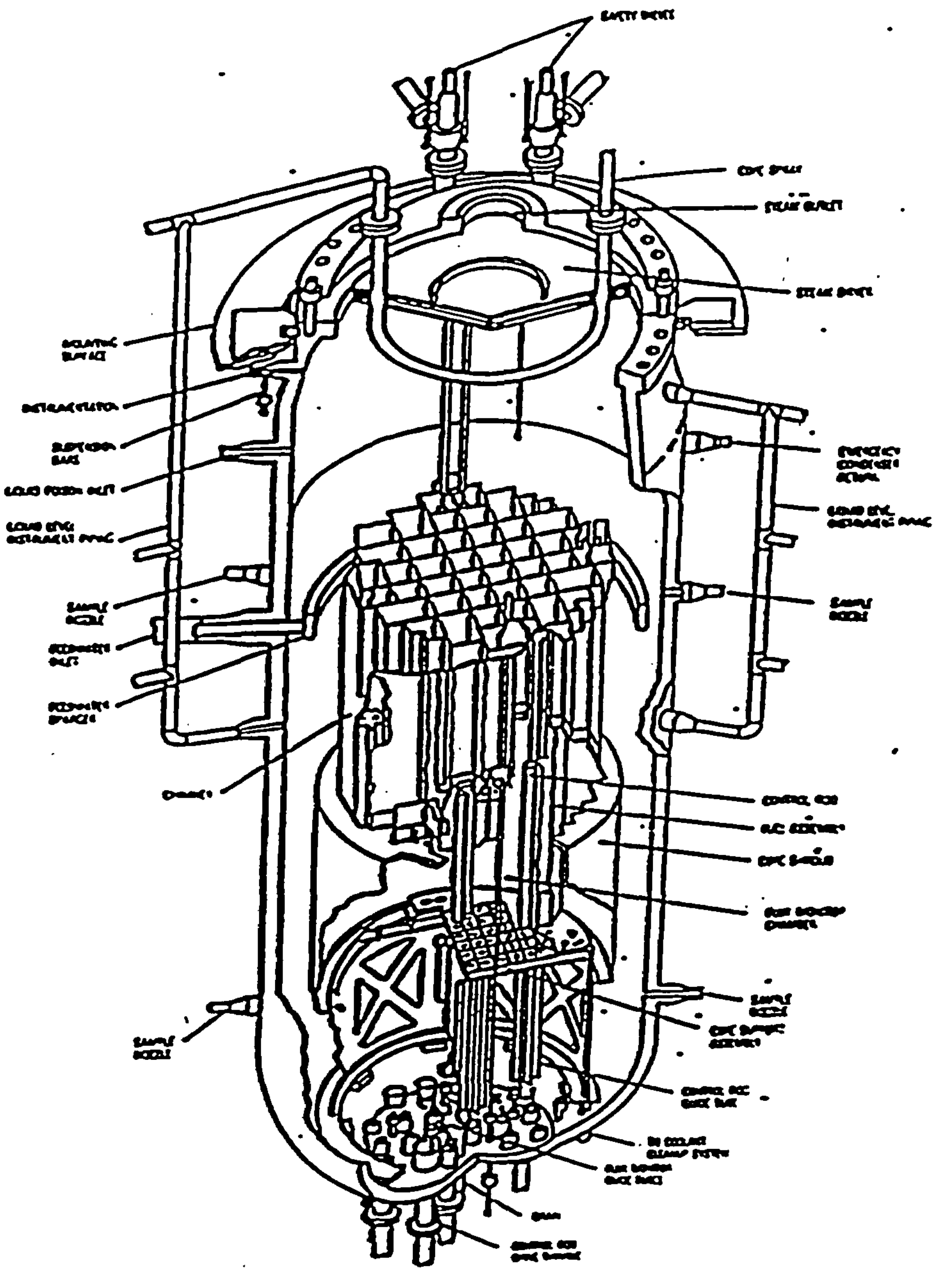
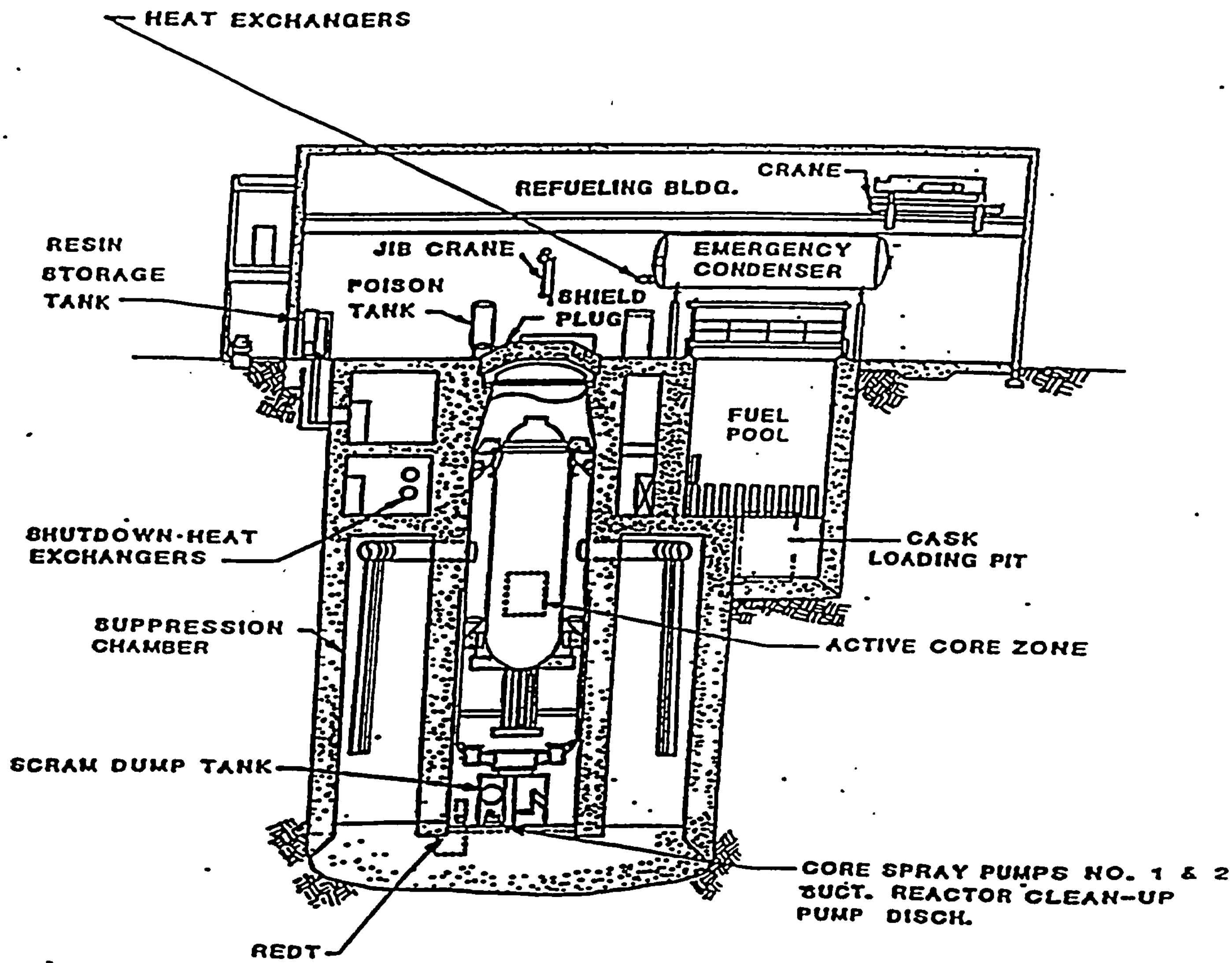


FIGURE 1.3

SECTIONAL VIEW THROUGH THE CAISSON



2. SAFSTOR DECOMMISSIONING ACTIVITIES

This section describes the activities associated with the decontamination and disassembly of the plant. Although detailed procedures for each activity identified are not provided, and the actual sequence of work may vary, the activity descriptions provide a basis not only for estimating, but also for understanding the expected scope of work, i.e., engineering and planning at the time of decommissioning.

The operation, shut down, and safe storage of the nuclear unit were described in detail in the decommissioning plan, "SAFSTOR Decommissioning Plan for the Humboldt Bay Power Plant, Unit No. 3" (Ref. 8). The activities and associated costs expended to date are therefore not repeated here. This study specifically addresses those activities and costs associated with the conclusion of the safe storage period and the subsequent decommissioning process.

The NRC defines SAFSTOR as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to a level that permits release for unrestricted use." The decommissioning scenario evaluated in this study presumes that decommissioning activities will officially start in 2004, prior to transfer of spent fuel into dry storage.

The SAFSTOR decommissioning plan prepared by PG&E primarily addressed the activities and tasks related to preparing and maintaining the facility in safe storage. The document was originally intended to be revised (updated) prior to initiating decommissioning activities in the year 2004. Under the current NRC decommissioning requirements, the SAFSTOR Decommissioning Plan was considered to be both a Preliminary Shutdown Decommissioning Activities Report (PSDAR) and a Defueled Safety Analysis Report (DSAR). As a result, PG&E submitted a PSDAR in February 1998 that describes planned decommissioning activities and associated schedule and cost (Ref. 9). The SAFSTOR Decommissioning Plan was renamed the DSAR, and it contains system descriptions, administrative controls, and accident analysis. At lease two years prior to license termination, PG&E will submit a License Termination Plan.

The current NRC guidance (Reg. Guide 1.184 Decommissioning of Nuclear Power Reactors) defines decommissioning in three phases. The current plant status (safe storage) is addressed in Phase II. This phase is applicable to the dormancy phase of the deferred decommissioning alternatives. Phase III pertains to the activities involved in license termination.

The TLG cost estimating methodology subdivides the decommissioning project into periods, based upon major milestones in the project. Continuing Phase II expenses, denoted as Period 2 in this study, are not addressed in detail. Phase III, addressing the activities associated with license termination, is subdivided into Periods 3 and 4 in the cost estimate. Period 5 addresses those activities required for site restoration. Post-Period 5 covers ISFSI operations, fuel transfer to the DOE, and ISFSI demolition.

2.1 PERIOD 2 – SAFE STORAGE AND DECOMMISSIONING PREPARATIONS

Current site activities include: preventive and corrective maintenance on essential systems, general building maintenance, operation and maintenance of heating and ventilation equipment, routine radiological inspections of contaminated structures, maintenance of structural integrity, and monitoring of environmental and radiation conditions.

Since the two adjoining fossil units are operational and site resources can be shared, the staff dedicated to Unit 3 is minimal. Consequently, to support decommissioning operations, PG&E will have to secure additional resources, both internally from the corporate organization and through external contractors.

Pre-decommissioning Period 2 activities are included in this study, one of which is the licensing and design of the ISFSI. The licensing and construction of this facility will allow the spent fuel currently stored in the plant's wet storage spent fuel pool to be relocated to a passive, dry storage system so that decommissioning of the components within the Refueling Building can proceed without restrictions caused by the storage of spent fuel in the storage pool.

The following additional preparatory activities are scheduled during Period 2 prior to start of the formal decommissioning: abatement of asbestos, performance of a vessel and internals activation analysis, performance of a radiological characterization survey of work areas, major components, and structures (including the drywell), sampling of internal piping and primary shield cores, development of cost and work control program, development of detailed work plans and schedules, development of a radioactive waste processing and disposal plan, and the development of the engineering decommissioning licensing basis.

2.2 PERIOD 3 - PREPARATIONS

In anticipation of decommissioning, preparations are undertaken to provide a smooth transition from safe storage. The organization required to plan and manage the intended decommissioning activities is assumed to be assembled from available utility staff and outside resources, as required. For purposes of this study, a decommissioning operations contractor (DOC) is utilized to manage the decommissioning and to manage and perform the physical decommissioning activities and associated management functions. A radwaste contractor will be employed to manage the processing and disposal of decommissioning waste, including the recycling of equipment, components, and material and the disposal of all decommissioning waste, including concrete and steel structural debris, contaminated soil, and associated hazardous and mixed waste.

2.2.1 Engineering and Planning

Significant technical and engineering planning and evaluation must be performed in preparation for physical decommissioning activities. Technical requirements documents are prepared for systems, components, and structures during each phase of the decommissioning. These engineering requirements are then transferred into specific documents for the preparation of material and services contracts and for the preparation of detailed work plans and work authorization documents. Also, regulations require the preparation of a license termination plan. The plan is required at least two years prior to the anticipated date of license termination. The plan includes a site characterization, description of the remaining dismantling activities, plans for site remediation, procedures for the final radiation survey, designation of any reuse of the site, an updated cost estimate to complete the decommissioning, and resolution of environmental concerns. The NRC will make the plan available for public comment. Plan approval will be subject to conditions and limitations as deemed appropriate by the NRC. Much of the information needed in preparing this submittal will have been used to develop the detailed engineering plans and procedures needed to support Period 4 activities.

Other engineering and planning work activities performed during Period 3 include: evaluating alternatives for the removal of highly radioactive reactor vessel components, identifying specialty contractors, selecting the methodology and requirements for systems and structures decontamination, preparing procedures for radioactive material disposal, and designing and procuring specialty tooling.

2.2.2 Site Preparations

In preparation for the actual decommissioning, the following physical tasks are performed and included in the cost estimate:

- The design and licensing of the ISFSI facility
- Constructing and modifying site support and storage facilities, as required.
- Processing and disposal of residual liquid, solid, and mixed waste inventories.
- Procuring waste containers, including specialty containers for the disposition of highly activated and hazardous materials. The types of containers needed to support decommissioning operations include strong-tight steel boxes and drums, shielded transport casks, dry fuel storage liners, high integrity containers, intermodal containers, and shipping transportation trailers.
- Developing procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste including dry active waste (DAW), resins, filter media, metallic and non-metallic components generated in decommissioning, site security and emergency programs, hazardous waste identification and processing, and industrial safety.

2.3 PERIOD 4 - DECOMMISSIONING OPERATIONS & LICENSE TERMINATION

The decommissioning cost estimate has divided this period into sub-periods to assist in the development of cost elements and to better understand the work sequence and the overall duration of the work phase. The spent fuel storage location and storage methodology during Period 4, significantly affects how costs are estimated. Therefore, costs for system removal are split into costs for system removal before and after spent fuel transfer to the ISFSI. System and structure operational requirements with the fuel in the pool control the overall sequence and approach to the HBPP3 decommissioning.

2.3.1 System Removal – Wet Fuel

This phase includes: construction of temporary facilities and shielding, modification of existing storage facilities to support the dismantling activities, decontamination of selected systems and components, procurement of specialty tooling, and modifications to systems and structures to support fuel transfer and handling of the waste from reactor vessel and spent fuel pool removal.

The following is a general chronological list of the system and component removal activities performed during this period.

- Removal of major turbine components, e.g. generator, turbine and condenser.
- Removal of components and systems in the Turbine Building, including piping, pumps, heat exchangers and associated mechanical and electrical components.
- Removal of electrical control boards, distribution buses, and transformers.
- Removal of Hot Machine Shop equipment and piping.

2.3.2 Fuel Transfer

The following is a general chronological list of the system and component removal activities performed during this period:

- Transfer of spent fuel to ISFSI
- Removal of spent fuel racks and fuel pool cleanup

2.3.3 System Removal – Dry Fuel (ISFSI)

The following is a general chronological list of the system and component removal activities performed during this period:

- Removal of the reactor vessel closure head. The head may be a candidate for decontamination; however, for estimating purposes it is assumed to be disposed of as low-level radioactive waste.

Segmentation of the head may be desirable to increase packaging efficiency and minimize its disposal volume.

- Removal and segmenting of the steam dryer, core spray piping, feedwater sparger and chimney, as required, for transport. Component segmentation may be performed in the reactor vessel; however, relocation to the spent fuel pool would allow greater control with respect to water clarity and provide greater flexibility in packaging, i.e., homogenization of the waste forms. Material meeting 10 CFR 61 Class C criteria or less may be routed for off-site disposal at a commercial shallow-land waste disposal facility.

- Disassembly/segmentation of remaining reactor internals, including the core shroud, core support assembly, control rod guide tube and other miscellaneous components. These operations will probably be confined to the reactor vessel due to the higher activation levels of the components.

- Segmentation/sectioning of the reactor vessel, placing segments into shielded containers. The operation is performed remotely, in-air, using a shielded work platform and a contamination control envelope. Sections are placed in liners and stored in the spent fuel pool. The liners are loaded into shielded transport casks for disposal at a commercial shallow-land waste disposal facility.

- Removal of control rod drive housings from reactor vessel bottom head and packaging for controlled disposal. The bottom head may be highly contaminated from the swarf generated from in-vessel segmentation activities. It may be advantageous to relocate the head to the spent fuel pool for additional processing and preparation for disposal. This will also significantly lower the working radiation levels within the drywell and allow disassembly work to proceed.

- Removal of systems and associated components as they become non-essential to the vessel removal operation, related decommissioning activities, or worker health and safety (e.g., waste collection and processing systems, electrical and ventilation systems, etc.).

- Removal of steel drywell liner and the steel vent pipes connecting the drywell to the suppression chamber. Contaminated surfaces can be designated for decontamination while activated portions are packaged for direct disposal. This activity would also include the removal of activated concrete from behind the drywell steel and the concrete floor slab at the bottom of caisson, and packaging the material for direct disposal.

- Decontamination and removal of the suppression chamber steel, Disposition as appropriate.

- Removal of contaminated equipment and material from the Radwaste Treatment and Refueling Buildings. Decontaminate the structures, e.g., scarifying concrete surfaces until residual levels of contamination are acceptable for unrestricted release.

- Decontamination of remaining contaminated site buildings and facilities. Package and dispose of all remaining low-level radioactive waste, and any remaining hazardous and toxic materials.

- Removal of remaining components, equipment, and plant services in support of the area release survey(s).

- Removal of contaminated soil and contaminated drain and catch basins. Remediation of the intake and discharge canals.

Components removed in the decontamination and dismantling of HBPP3 will be routed to an on-site central processing area. Material that has been preliminarily screened to be free of contamination will be shipped to an offsite processing facility where final release surveys will be conducted. Contaminated material will be characterized and segregated for off-site processing (disassembly, chemical cleaning, volume reduction, waste treatment, etc.) and/or packaged for controlled disposal at the designated low-level radioactive waste disposal facility.

2.3.4 Building Demolition

Buildings in the Restricted Area (RA) will be decontaminated as necessary to allow conventional demolition. Structures will be removed down to three feet below grade.

Demolition debris will be packaged, shipped, and disposed of at Envirocare. The waste will be packaged in intermodal containers and shipped by barge to a railhead in San Francisco or Portland for final rail shipment to Envirocare.

2.3.5 Final Site Survey – License Termination

Incorporated into the License Termination Plan, the Final Survey Plan details the radiological surveys to be performed once the decontamination activities are completed. The Final Site Survey will be performed in accordance with MARSSIM. This document delineates the statistical approaches to survey design and data interpretation acceptable to the Environmental Protection Agency (EPA) and the NRC. It also identifies state-of-the-art, commercially available, instrumentation and procedures for conducting radiological surveys.

Use of this guideline ensures that survey design and implementation are conducted in a manner that provides a high degree of confidence that NRC criteria are satisfied. Once the survey is complete, the results are provided to the NRC in a format that can be verified. The NRC then reviews and evaluates the information, mobilizes a team to perform an independent confirmation sample survey of radiological site conditions, and makes a determination on final termination of the license.

The NRC will terminate the license if it determines that the site remediation has been performed in accordance with the License Termination Plan and the Final Survey Plan, and that appropriate documentation has been presented to demonstrate that the facility is suitable for release. Once all applicable requirements are satisfied, the NRC can terminate the Part 50 license.

2.4 PERIOD 5 - SITE RESTORATION

Excavated areas will be backfilled to grade using clean fill. A small volume of clean asphalt paving will be available and used as fill. Site areas affected by the dismantling activities are cleaned and the plant area graded as required to prevent ponding and inhibit the refloating of subsurface materials.

2.5 POST-PERIOD 5 - ISFSI OPERATIONS AND DEMOLITION

Following the transfer of the spent fuel inventory from the Refueling Building, the dry storage facility will operate independently of the nuclear unit. The ISFSI will continue to operate until all spent fuel and greater than Class C (GTCC) material has been transferred to the DOE. This study assumes that the DOE will be able to complete the transfer of spent fuel from HBPP3 by the year 2015.

At the conclusion of the transfer process, the ISFSI will be decommissioned. The storage modules are not assumed to be activated from the storage of fuel, due to the age of the fuel when placed and the relatively short residence time. Consequently, this estimate does not include the cost of any significant decontamination of the ISFSI facility. Confirmation of the radiological status will be obtained through surveys and sampling of the modules.

The Commission will terminate the ISFSI 10 CFR 72 license when it determines that site remediation has been performed in accordance with a license termination plan and the terminal radiation survey and associated documentation demonstrate that the structure is suitable for release. Once the requirements are satisfied, the NRC can terminate the license for the ISFSI.

The dry storage modules are then disposed of, the concrete loading ramps are removed, and the area graded and landscaped to conform to the surrounding environs.

3. COST ESTIMATE

A site-specific cost estimate was prepared for decommissioning HBPP3. The estimate accounts for the unique features of the site, including the nuclear boiler, electric power generating systems, structures, and supporting facilities. The basis of the estimate and the sources of information, methodology, site-specific considerations, assumptions, and total costs are described in this section.

3.1 BASIS OF ESTIMATE

The estimate was developed using work areas as the incremental unit. As part of the 1997 cost estimate, each accessible area was visually inspected and a physical inventory of each area was documented. Specific consideration included material accessibility and egress, radiological conditions, and physical limitations for staging work crews.

Drawings and other documentation were used to plan and schedule activities in high radiation areas and areas currently inaccessible due to the plant's configuration. The unit factors used in developing equipment and component removal costs were adjusted for the working conditions determined for each area. Adaptation of the unit factors was accomplished by the manipulation of the duration adjustment variables or "Work Difficulty Factors" (WDF's).

The waste stream is assumed to be transferred to an on-site radioactive waste processor for recycling and disposal. Class A low-level radioactive waste generated in the decontamination and dismantling of HBPP3 is assumed to be buried at the Envirocare facility in Clive, Utah. Class B and C low-level radioactive waste is assumed to be buried at the Southwest Compact's future disposal facility or nationally available equivalent.

Spent fuel is assumed to be relocated to an on-site ISFSI. This allows for decontamination and dismantling activities to proceed on the refueling building without the current constraint to maintain active spent fuel storage pool systems and services, as well as to eliminate any safety issues associated with dismantling activities in the vicinity of the pool.

HBPP3 above grade structures will be demolished using standard methods and all demolition debris will be shipped off site to Envirocare. Below grade structures will be decontaminated and left in place.

As the licensee, PG&E will oversee the decommissioning operations. The plant staff will be augmented with the resources necessary to ensure a safe and efficient operation. This organization will supervise the decontamination and dismantling of the nuclear unit. Oversight will continue in a reduced capacity during site restoration and beyond, as dictated by the management of the spent fuel.

3.2 METHODOLOGY

The methodology used to develop this cost estimate follows the basic approach originally presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," (Ref. 10) and the US DOE "Decommissioning Handbook" (Ref. 11). These references utilize a unit cost factor method for estimating decommissioning activity costs, which simplifies the estimating calculations. Unit cost factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) were developed from the labor cost information provided by PG&E. The activity-dependent costs are estimated with the item quantities (cubic yards, tons, inches, etc.) developed from plant drawings and inventory documents.

The unit cost factors used in this study reflect site-specific costs as well as the latest available information about worker productivity in decommissioning. Lessons learned from the Shippingport Station Decommissioning Project, completed in 1989, the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997, and from TLG's involvement in the decommissioning planning and engineering for the Big Rock Point, Maine Yankee, Shoreham, Yankee Rowe, Trojan, Rancho Seco, and Pathfinder nuclear units are reflected within this estimate.

The unit factor method provides a demonstrable basis for establishing reliable cost estimates. The detail available in the unit cost factors for activity time, labor (by craft), and equipment and consumable costs provide assurance that cost elements has not been omitted. These detailed unit cost factors, coupled with the plant-specific inventory of piping, components, and structures provide a high degree of confidence in the reliability of the cost estimates.

<u>Work Difficulty Factors</u>

WDF were assigned to each area, commensurate with the inefficiencies associated with working in confined hazardous environments. The ranges used for the WDFs are as follows:

Access Factor	0% - 40%
Respirator Protection Factor	0% - 50%
Radiation/ALARA Factor	0% - 100%
Protective Clothing Factor	0% - 30%
Work Break Factor	8.33%
Alpha Adjustment Factor	0% - 50%

These factors and their associated range of values were developed in conjunction with the Atomic Industrial Forum's guideline. The factors (and their suggested application) are discussed in more detail in that publication. The WDF assigned to each work area is delineated in Appendix A.

An activity duration critical path was used to determine the total decommissioning program schedule. The program schedule is used to determine the period-dependent costs for program management, administration, field engineering, equipment rental, quality assurance, and security. The study used actual PG&E craft labor rates and adjusted them for the local region. Some of the costs for removal of radioactive components/ structures were based on information obtained from the "Building Construction Cost Data," published by R. S. Means (Ref. 12). Examples of unit cost factor development are presented in the AIF/NESP-036 study. Appendix B presents the detailed development of a typical site-specific unit cost factor. Appendix C provides the values contained within one set of factors developed for the HBPP3 analyses.

3.3 FINANCIAL COMPONENTS OF THE COST MODEL

TLG's cost model is comprised of a multitude of distinct cost line items, calculated using the unit cost factor methodology described in Section 3.2. Period-dependent and collateral costs are added to produce a comprehensive accounting of the identified expenditures.

A contingency cost is also included in the total estimated decommissioning cost for HBPP3.

3.3.1 Contingency

Inherent in any cost estimate that does not rely on historical data is the inability to specify the precise source of costs imposed by factors such as tool breakage, accidents, illness, weather delays, labor stoppages, etc. Contingency fulfills this role in TLG's cost model. Contingency is added to each line item to account for costs that are difficult or impossible to develop analytically. Such costs are historically inevitable over the duration of a job of this magnitude; therefore, this cost analysis includes monies to cover these types of expenses.

The activity- and period-dependent costs are combined to develop the total decommissioning costs. A contingency is then applied on a line-item basis, using one or more of the contingency types listed in Chapter 13 of the AIF/NESP-036 Guidelines Study. This reference document also identifies the types of unforeseeable events that are likely to occur in decommissioning and provides guidelines for the application of contingency.

"Contingencies" are defined in the "Project and Cost Engineers' Handbook," (Ref. 13) as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this estimate are based upon ideal conditions and maximum efficiency; therefore, consistent with industry practice, a contingency factor has been applied. It should be noted that contingency, as used in this estimate, does not account for price escalation and inflation in the cost of decommissioning over the program duration.

The use and role of contingency within decommissioning estimates is not a "safety factor issue." Safety factors provide additional security and address situations that may never occur. Contingency funds are expected to be fully expended throughout the program. They also provide assurance that sufficient funding is available to accomplish the intended tasks. An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize a successful conclusion to the decommissioning process.

The most technologically challenging task in decommissioning a nuclear generating unit will be the disposition of the reactor vessel and internal components, which have become highly radioactive after a lifetime of exposure to radiation produced in the core. The disposition of these highly radioactive components forms the basis for the critical path (schedule) for decommissioning operations. Cost and schedule are interdependent and any deviation in schedule may have an impact on cost for performing a specific activity.

Disposition of the reactor vessel internal components involves the underwater cutting of complex components that are highly radioactive. Costs are based upon optimum segmentation, handling, and packaging scenarios. The schedule is primarily dependent upon the turnaround time for the heavily shielded shipping casks, including preparation, loading, and decontamination of the containers for transport. The number of casks required is a function of the pieces generated in the segmentation activity, a value calculated on optimum performance of the tooling employed in cutting the various subassemblies. The risk and uncertainties associated with this task are that the expected optimization may not be achieved, resulting in delays and additional program costs. For this reason, contingency must be included to mitigate the consequences of the expected inefficiencies inherent in this complex activity, along with related concerns associated with specialty tooling modifications and repairs, field changes, discontinuities in the coordination of plant services, system failure, water clarity, lighting, computer-controlled cutting software corrections, etc. Experience in decommissioning other plants in the past has shown that many of these problem areas have occurred during and in support of the segmentation process. Contingency dollars are an integral part of the total cost to complete this task. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, follow-on related activities.

The following list is a composite of some of the activities assembled from past decommissioning programs in which contingency dollars were needed to respond to, compensate for, and/or provide adequate funding of decontamination and dismantling tasks:

Incomplete or Changed Conditions:

- Unavailable/incomplete operational history - that led to a recontamination of a work area because a sealed cubicle (incorrectly identified as being non-contaminated) was breached without controls.

- Surface coatings covering contamination that, due to an incomplete characterization, required additional cost and time to remediate.

- Additional decontamination, controlled removal, and disposition of previously undetected (although at some sites, suspected) contamination due to access gained to formerly inaccessible areas and components.

- Unrecorded construction modifications, facility upgrades, maintenance, enhancements, etc., that precipitated scheduling delays, more costly removal scenarios, additional costs (e.g., for re-engineering, shoring, structural modifications), and compromised worker safety.

Adverse Working Conditions:

- Lower than expected productivity due to high temperature environments that resulted in a change in the working hours (shifting to cooler periods of the day) and additional manpower.

- Confined space, low-oxygen environments where supplied air was necessary and additional safety precautions that prolonged the time required to perform required tasks.

Maintenance, Repairs and Modifications

- Facility refurbishment required to support site operations, including those needed to provide new site services, as well as to maintain the integrity of existing structures.

- Damage control, repair, and maintenance from birds' nesting and fouling of equipment and controls.

- Building modification, i.e., re-supporting of floors to enhance loading capacity for heavily shielded casks.

- Roadway upgrades on site to handle heavier and wider loads; roadway rerouting, excavation, and reconstruction.

- Requests for additional safety margins by a vendor.

- Requests to analyze accident scenarios beyond those defined by the removal scenarios (requested by the NRC to comply with "total scope of regulation").

- Additional collection of site runoff and processing of such due to disturbance of natural site contours and drainage.

- Concrete coring for removal of embedments and internal conduit, piping, and other potentially contaminated material not originally identified as being contaminated.

- Modifications required to respond to higher than expected worker exposure, water clarity, water disassociation, and hydrogen generation from high temperature cutting operations.

- Additional waste containers needed to accommodate cutting particulates (fines), inefficient waste geometries, and excess material.

Labor

- Turnover of personnel, e.g., craft and health physics. Replacement of labor is costly, involving additional training, badging, medical exams, and associated processing procedures. Recruitment costs are incurred for more experienced personnel and can include relocation and living expense compensation.

- Additional personnel required to comply with NRC mandates and requests.

- Replacement of personnel due to non-qualification and/or incomplete certification (e.g., welders).

Schedule

- Schedule slippage due to a conflict in required resources, i.e., the licensee was forced into a delay until prior (non-licensee) commitments of outside resources were resolved.

- Rejection of material by NRC inspectors, requiring refabrication and causing program delays in activities required to be completed prior to decommissioning operations.

Weather

- Weather-related delays in the construction of facilities required to support site operations (with compensation for delayed mobilization made to vendor).

- Frozen crane hydraulics prior to a major lift.

The cost model incorporates considerations for items such as those described above, generating contingency dollars (at varying percentages of total line-item cost) with every activity.

3.3.2 Financial Risk

TLG believes that this estimate is the best available, under the constraints and conditions outlined in the assumptions (Section 3.5). However, in determining the extent of the financial liability faced by the owners of HBPP3, there are uncertainties other than the routine ones that contingency addresses. These additional uncertainties consist of such items as changes in work scope, pricing (e.g. burial costs), job performance, schedule increases caused by changes in plant conditions, variations in the cost of labor (both craft and staff), severance, and other variations that could conceivably, but not necessarily, occur. Consideration of such items may be necessary to address the question concerning how costly the decommissioning project could become, within a range of probabilities. TLG considers these types of costs under the broad term "financial risk." Financial risk is typically addressed through a probability analysis using a Monte Carlo-type simulation program. The output of such a simulation typically includes a curve and range of probabilities for various cost estimates.

Included within the category of financial risk are:

- Delays in approval of the decommissioning (or license termination) plan due to intervention, public participation in local community meetings, legal challenges, state and local hearings, etc.

- Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.

- Regulatory changes, e.g., affecting worker health and safety, site release criteria, waste transportation, and disposal.

- Policy decisions altering federal and state commitments, e.g., in the ability to accommodate certain waste forms for disposition, or in the timetable for such.

- Pricing changes for basic inputs, such as labor, energy, materials, and burial. Some of these inputs may vary slightly, e.g., -10% to +20%; burial could vary from -50% to +200% or more.

TLG did not perform a risk analysis for this estimate and therefore this report does not include any additional costs to address the risks associated with changes in the base assumptions of the study.

3.4 SITE SPECIFIC CONSIDERATIONS

3.4.1 Spent Fuel Disposition

The estimate assumes that the ISFSI will commence operation in 2006. The proposed ISFSI transfer date will allow the facility decommissioning to proceed without constraints for spent fuel caretaking activities. The facility will have sufficient capacity to handle the inventory of 390 spent fuel assemblies currently in the spent fuel storage pool. The ISFSI design is for a multi-purpose (storage and transport) dry canister within a vertical multi-purpose steel cask. The ISFSI is also designed and sized to handle one container of greater than Class C (GTCC) waste that will be generated during the reactor vessel dismantling. The ISFSI will operate until 2015, the current projected date for the DOE to remove all spent fuel from the facility. Any delays in the transfer date to the DOE will increase the overall operations and maintenance cost.

The ISFSI cost estimate includes the cost for the ISFSI canisters, the concrete storage facility, road to storage facility, all engineering, construction, and licensing costs, and the costs and cask handling. The ISFSI operational and maintenance costs include inspections and security.

3.4.2 Reactor Vessel and Internal Components

The reactor vessel and internal components will be segmented in place and transported for disposal in shielded transportation casks. Segmentation of the less activated components is performed in the spent fuel storage pool to the maximum extent practicable. The highly activated components can be disassembled in the vessel as long as water clarity is maintained. The vessel is segmented in place, using a mast-mounted cutter.

The dismantling of reactor internal components at HBPP3 will generate radioactive waste generally unsuitable for shallow land disposal (GTCC). Although the material is not classified as high-level waste, DOE has indicated it will accept title to this waste for disposal at the future high-level waste repository. However, the DOE has not yet established acceptance criteria or a disposition schedule for this material, and numerous questions remain as to the ultimate disposal cost and waste form requirements. As such, for purposes of this study, the GTCC waste has been packaged and disposed of as high-level waste, at a cost equivalent to that envisioned for the spent fuel.

Main steam and feedwater piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzles.

The estimate further assumes that the fuel failures that occurred released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes has been prevented from reaching levels exceeding those which permit the major NSSS components to be shipped under current DOT regulations and to be buried within the requirements of 10 CFR 61.

The cost to remove and dispose of 48 control rod blades is included in the estimate.

3.4.3 Main Turbine and Condenser

The main turbine is dismantled using conventional maintenance procedures. The generator, turbine rotors, and shafts are removed to a laydown area. The lower turbine casing is removed from its anchors by controlled demolition. The main condensers are also disassembled and moved to a laydown area. Each component is surveyed and designated for either decontamination, volume reduction, and conventional or controlled disposal.

The removal cost of the condenser and the turbine has been adjusted by revising the WDF to account for the presence of alpha contamination.

3.4.4 Plant Systems

Due to the high levels of alpha contamination, mechanical cutting is the primary method of removing mechanical and electrical components. This method will minimize the potential of alpha particle contamination and the remediation requirements associated with lead -based paint on the exterior piping surfaces.

The WDF and the unit cost factors associated with system removal activities in areas with known alpha contamination have been adjusted and increased by a factor of 1.5 to provide an additional allowance for the increased difficulty of performing work activities in areas containing alpha contamination.

3.4.5 Humboldt Bay Unit 3 Facilities

Typically surface contamination can be removed by scarification where the contamination is removed with the spalled or abraded concrete surface. This technique is most effective on smooth, unbroken surfaces. Over time, the concrete at Humboldt Bay has experienced cracking from the high seismic activity in the area providing pathways for contamination transport. In addition, the concrete surfaces were originally uncoated and were subject to additional contamination deposits due to failed fuel in early cycles. As such, the contamination has likely migrated to depths greater than effectively removed by surface scarification techniques. This condition was observed during the plant stack removal project where the vendor had difficulty in meeting the free-release criteria for the stack material, even after extensive surface decontamination. As a result of this expected plant condition and for the purposes of this estimate, structural material removed as part of the decommissioning project was assumed to be disposed of at a LLRW disposal facility. Although this same condition is expected to exist in below grade structures, due to the high water table and resulting cost to remove below grade structures, these structures will be decontaminated and surveyed in place. Decontaminating below-grade structures to free-release is expected to be more cost-effective than complete removal.

Significant alpha contamination exists within primary systems and as fixed contamination in the Refueling, Radwaste, and Turbine buildings. The extent of the alpha contamination will require additional radiological controls and will reduce the efficiency of component removal activities. These controls will include: additional resources to perform surveys and establish contamination controls, additional time to obtain, dry, and prepare for counting alpha samples, additional respiratory protection requirements and controls, additional time for the set up of localized control of the contamination and additional nonproductive time for personnel involved in removal activities due to the alpha contamination. Therefore, the worker inefficiency factors for building decontamination activities in specified work areas has been increased (compared to the 1997 study) by a factor of 1.05 to account for these limitations.

The caisson surrounding the reactor vessel and constituting the containment structure will remain in place. The caisson will not be able to be removed while the adjacent fossil-fueled units are still operational.

The additional resources and work activities during the decommissioning will necessitate additional facilities. This estimate provides for the following new facilities: radiation protection counting facility, craft entry facility, locker and sanitary facilities for project personnel, a radwaste packaging and container loading facility, temporary office facilities, and a temporary control room facility. An allowance has also been provided in the Period 3 costs for modification and upgrade of the Refuel Building crane. These upgrades are required prior to the start of decommissioning work in the building.

The HBPP site is physically small and members of the public can access within 100 feet of the current restricted area. As such, the Radwaste Process Facility will be moved closer to the center of the site to reduce potential members of the public dose.

The existing Solid Radwaste Storage Building located on the north side of Unit 3 will be converted into a combination radiation protection counting facility, radiation protection office area, and a new craft entry point. Modifications to this facility include counting room shielding, interior office space and furniture, radiation laboratory monitoring and measuring equipment, and installation of exit portal radiation monitors. The perimeter fence and in-plant security barriers will be moved as appropriate to conform to the Site Security Plan in force at the various stages of the project.

Before demolition of the turbine building can begin, the existing control room must be de-energized and an alternative control room will be erected to monitor radiation effluent and other permitted discharges. In addition the current count room facility must be moved prior to movement of the turbine generator.

A radwaste shipping and handling facility will be provided to support the radwaste removal and recycling contractor. A radioactive waste packaging area will be created in the lower level of the Turbine Building. This facility will rely on the existing mechanical, electrical, and other equipment that is currently available in the area. Also, a waste shipment loading area will be constructed. This facility will be a metal-sided building, (approximately 50 foot by 60 foot) with access for large moving and lifting equipment to support waste shipping operations.

Craft and technical office trailers and support facilities are provided for in the estimate, as is the installation of a sanitary pump lift station to support the additional project staff.

All buildings scheduled for demolition will be removed to a nominal depth of three feet below grade, with the decontaminated or non-contaminated sub grade foundations remaining in place. Holes will be drilled in each of the foundation basemats to allow for natural drainage. Building foundations will be backfilled with clean backfill (and a nominal volume of clean asphalt), and the site will be graded and landscaped. All areas affected by dismantling activities will be cleaned up, covered with loam, and seeded.

A cost has been included for the survey of structures after decontamination and prior to the demolition and disposal of the debris. Partial decontamination and survey of the structure will allow demolition of the structure without the additional requirements imposed due to radioactive material monitoring and control.

Yard drainage piping including contaminated soils surrounding the drain system will be excavated and removed. The existing circulating water discharge piping will be abandoned in place.

The discharge canals and portions of the intake canal will be remediated. Contaminated material will be excavated and disposed of as Class A waste.

3.4.6 Transportation Methods

Class B and C low-level radioactive waste produced and destined for controlled disposal will be moved overland by truck or shielded van to the primary burial site (Southwest Compact site) assumed to be no more than 1,000 miles away. Class A waste (including waste from the reactor vessel segmentation) will be shipped by truck to the Envirocare burial site. Building demolition debris and waste soil will be shipped using intermodal containers via barge and then rail to Envirocare.

Recycling waste will be transported by the waste contractor to its recycling center. The cost of transportation of recycled waste is included in the bulk recycling rate of $2 per pound.

Portions of the reactor vessel and internal components will be transported in accordance with 10 CFR 71, as Type B and C waste. It is conceivable that the reactor, due to its limited specific activity, could qualify as Low Specific Activity (LSA) II or III. However, the high radiation levels on the outer surface would require that additional shielding be incorporated with the packaging to attenuate the dose to levels acceptable for transport under 49 CFR 173 (Ref. 14). Contaminated piping, components, and structural steel other than the reactor vessel and internals, will qualify as LSA – I, II, or III or SCO-I, or II, as described in 49 CFR Part 173. The contaminated material will be packaged in Industrial Packages (IP I, II, or III) for transport unless demonstrated to qualify as their own shipping containers.

Shielded truck casks will be used to transport highly activated metal produced in the segmentation of the reactor vessel and internal components. Cask shipments may exceed 95,000 pounds due to the weight of the vessel segments(s), supplementary shielding, cask tie-downs and the tractor-trailer. The maximum curies per shipment assumed permissible is based upon the license limits of available shielded shipping casks. The number and curie content of vessel segments are selected to meet these limits. The number of cask shipments out of the Refueling Building is expected to average one every two weeks. Non-cask shipments will be limited to two per week.

An allowance has been provided in the estimate for the purchase of eight special trailer beds. State law restricts the size of the trucks on local roads. Since shortened truck beds are not readily available for rental, PG&E has decided to purchase the equipment.

3.4.7 Coordination with Units 1 and 2

This estimate includes the removal of the entire site drainage network. A portion of the excavated soil will require remediation and will be disposed of as radioactive waste. The essential portions of the yard drainage system that supports Units 1 or 2 will be replaced.

In accordance with NRC requirements, and based upon known radioactive contamination, radiological surveys of Units 1 and 2 will be conducted as part of the Final Site Survey. The surveys will be coordinated with any planned outages or maintenance for either unit.

3.4.8 Site Conditions Following Decommissioning

It is assumed that the Unit 3 structures and site facilities will be dismantled following their decontamination. Structures would be removed to a nominal depth of 3 feet below grade. The voids would be backfilled with clean debris and capped with soil. The site would then be graded to conform to the adjacent landscape. Vegetation would be established to inhibit erosion.

The canals would remain for use by the operating units; however, non-essential structures could be removed. The switchyard will remain in place, as well as the site access road.

3.5 ASSUMPTIONS

The following additional factors and conditions were used in developing the decommissioning cost estimate for HBPP3. Radwaste estimating assumptions are contained in Section 5.

3.5.1 Estimating Basis

The estimate is performed in accordance with the methodology described in the AIF/NESP-036 study. Decommissioning costs are reported in the year of projected expenditures; however, the values are reported in 2002 dollars for the current estimate. Costs are not inflated or escalated over the period of performance.

Plant drawings, equipment, and structural specifications, including construction details, were provided by PG&E. TLG personnel prepared the inventory of plant equipment.

3.5.2 Labor Costs

Although PG&E will oversee the decommissioning operations, this study assumes that PG&E hires a decommissioning operations contractor (DOC) to handle planning, engineering, procurement, field supervision, and labor. A separate waste disposal contractor will also be contracted to provide bulk one-stop recycling and disposal of decommissioning waste.

Utility staffing requirements will vary with the level of effort associated with the various phases of the project. Once the decommissioning program starts, only those staff positions necessary to support the decommissioning program are included. There are no costs reflected within the estimate for the transition of the maintenance organization to decommissioning, e.g., separation packages, re-training, severance, incentives, etc.

The craft labor required to decontaminate and dismantle the nuclear unit will be acquired through standard contracting practices. The current cost of labor from Diablo Canyon was adjusted for regional differences, escalated to 2002 dollars and used in the estimate. Costs for site administration, operations, construction and maintenance personnel are based upon current PG&E salary information. Engineering services for such items as writing activity specifications, detailed procedures, and work procedures are assumed to be provided by the DOC.

The WDF and unit cost factors for component removal and for selective building structural decontamination have been adjusted to account for the affects of alpha contamination. Mechanical cutting using saws and portable pipe cutters is the primary method of component removal used in the estimate.

3.5.3 General

The existing plant equipment inventory is obsolete and only suitable for scrap as deadweight quantities. No equipment is salvageable. Scrap generated during decommissioning is not recognized as having any value because (1) scrap value generally offsets scrap removal and processing costs and (2) scrap materials have a relatively low market value. Scrap processing and site removal costs are not included in the estimate.

Clean asbestos will be disposed in an approved landfill. Contaminated asbestos will be buried as radioactive waste.

PG&E will provide the electrical power for decommissioning. Current Humboldt Bay electricity rates are used.

PG&E will remove all items of furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, other similar mobile equipment, and other such items of personal property owned by PG&E that will be easily removed without the use of special equipment at no cost or credit to the project.

Existing warehouses will remain for use by PG&E and its subcontractors.

The study follows the principles of ALARA through the use of work duration adjustment factors. These factors adjust the time and cost for performing tasks after consideration of factors such as use of protective clothing and respirators and the effect of indoctrination and mock-up training. These items lengthen a task's duration, which increase the costs and lengthen the overall schedule. ALARA planning is considered in the costs for engineering and planning, and in the development of activity specifications and detailed procedures.

Nuclear liability insurance provides coverage for off-site damage or injuries due to radiation exposure from equipment and material. Nuclear property insurance provides protection against direct physical damage to on-site property by a broad range of causes including, radioactive contamination, fires, floods, etc. This estimate includes the premium cost for both liability and property insurance. The premiums are adjusted to reflect the relative changes in risk during the various phases of decommissioning. Insurance is required until both the Part 50 and Part 72 licenses are terminated.

The perimeter fence and in-plant security barriers will be moved as appropriate to conform with the Security Plan in force at the various stages in the project. No additional security or Regulatory revisions have been included as a result of the events of 09/11/2001. A new craft entry point will be installed to support Unit 3 decommissioning without interfering with the remaining operating generating units. A new radiological protection counting room and storage facility will also be constructed to support the decommissioning. Additional survey equipment will be purchased to support the large radiological protection program and the Final Status Survey (FSS) effort.

The existing electrical switchyard will remain after decommissioning in support of the remaining site generating units and the utility's electrical transmission and distribution system.

Underground concrete pipe will be decontaminated and abandoned. Underground steel pipe will be removed, surveyed for contamination, removed from the site, and disposed of as clean scrap. Electrical manholes will be backfilled with suitable earthen material and abandoned.

It is assumed that all site vestiges are to be removed to a nominal depth of three feet below grade, with the decontaminated and non-contaminated sub grade foundations remaining in place. Holes will be drilled in each of the foundation basemats to allow for natural drainage. Building foundations will be backfilled with clean fill, and the site will be cleaned up, covered with loam, and seeded. The caisson encapsulating the reactor vessel compartment will be decontaminated and abandoned in place. Excavation and removal of the caisson is not practical without affecting the operation of the adjacent generating units.

Wherever shared process systems exist, between the fossil operations and Unit 3, the Unit 3 systems will be isolated from the remaining operational portions. Non-nuclear portions of these systems that contain residual contamination will be remediated and decontaminated as part of the dismantling of the operating unit unless the respective system is removed or replaced sooner.

No groundwater remediation is expected to be required. A nominal amount of mixed waste will be disposed of and 22,000 cubic feet of contaminated soil will require removal and disposal.

The remediation of the discharge canal requires the installation of a cofferdam. This will allow remediation of the canal without interruption of the operating units. Trap rock and sediment will be mechanically removed, trap rock will be washed to remove loose radioactive material. Contaminated rock and sediment will be packaged and buried. Recycled rock and new material will be replaced to return the canal to its original condition.

3.6 COST ESTIMATE SUMMARY

A summary of the decommissioning costs and annual expenditures is provided in the cash flow summary in Table 3.1a. Table 3.1b is a similar table of annual expenditures but omits those costs disallowed by the California Public Utility Commission (CPUC). Table 6.1 provides a breakdown of those same decommissioning costs into the components of decontamination, removal, packaging, etc. The costs were extracted from the detailed reports in Appendices D & E, which provide a detailed listing of activities and associated costs for the decommissioning scenario.

TABLE 3.1a

SCHEDULE OF EXPENDITURES
(2002 Dollars)[1]

Year	PG&E Labor	Equipment & Materials	Contractor Labor	Burial	Other	Yearly Totals
1996-2000	0	0	0	0	21,325,681	21,325,681
2001	0	0	0	0	286,626	286,626
2002	0	0	0	0	7,300,527	7,300,527
2003	0	0	0	0	1,189,667	1,189,667
2004	7,059,912	419,248	8,159,749	14,932	9,726,735	25,380,576
2005	14,213,432	3,410,413	16,603,978	6,308,413	13,390,891	53,927,127
2006	14,476,102	8,525,690	11,000,608	18,784,842	4,811,935	57,599,178
2007	13,591,464	8,525,690	10,273,829	18,784,842	4,683,067	55,858,893
2008	8,832,691	8,549,048	9,118,902	18,836,308	4,684,443	50,021,392
2009	2,135,885	1,710,261	2,063,167	1,388,174	3,982,329	11,279,817
2010	739,628	38,558	739,628	0	1,243,481	2,761,295
2011	739,628	38,558	739,628	0	1,243,481	2,761,295
2012	741,655	38,663	741,655	0	1,246,888	2,768,860
2013	739,628	38,558	739,628	0	1,243,481	2,761,295
2014	739,628	38,558	739,628	0	1,243,481	2,761,295
2015	361,904	18,866	361,904	0	1,648,173	2,390,847
	64,371,558	31,352,111	61,282,306	64,117,513	79,250,884	300,374,371

1 Columns may not add due to rounding

TABLE 3.1b

SCHEDULE OF EXPENDITURES, EXCLUDING CPUC DISALLOWANCES (2002 Dollars)[1]

Year	PG&E Labor	Equipment & Materials	Contractor Labor	Burial	Other	Yearly Totals
1996-2000	0	0	0	0	21,325,681	21,325,681
2001	0	0	0	0	286,626	286,626
2002	0	0	0	0	7,300,527	7,300,527
2003	0	0	0	0	1,189,667	1,189,667
2004	7,059,912	419,248	8,159,749	14,932	9,726,735	25,380,576
2005	14,213,432	3,390,798	16,427,441	6,253,924	13,390,891	53,676,486
2006	14,476,102	8,503,042	10,748,380	18,721,927	4,811,935	57,261,386
2007	13,591,464	8,525,690	10,273,829	18,784,842	4,683,067	55,858,893
2008	8,832,691	8,549,048	9,118,902	18,836,308	4,684,443	50,021,392
2009	2,135,885	1,606,564	2,042,428	1,388,174	3,982,329	11,155,380
2010	739,628	38,558	739,628	0	1,243,481	2,761,295
2011	739,628	38,558	739,628	0	1,243,481	2,761,295
2012	741,655	38,663	741,655	0	1,246,888	2,768,860
2013	739,628	38,558	739,628	0	1,243,481	2,761,295
2014	739,628	38,558	739,628	0	1,243,481	2,761,295
2015	361,904	18,866	361,904	0	1,648,173	2,390,847
	64,371,558	31,206,150	60,832,802	64,000,108	79,250,884	299,661,502

1 Columns may not add due to rounding

4. SCHEDULE ESTIMATE

The schedule for the decommissioning scenario considered in this study follows the sequence presented in the AIF/NESP-036 study, with minor changes to reflect recent experience and site-specific constraints. In addition, the scheduling has been revised to reflect the spent fuel management plan outlined for HBPP3.

Appendix F presents a schedule for the 2006 SAFSTOR decommissioning alternative and the supporting assumptions. The key activities listed in the schedule do not reflect a one-to-one correspondence with those activities in the Appendix D cost table, but reflect dividing some activities for clarity and combining others for convenience. The schedule was prepared using the "Microsoft Project for Windows" computer software (Ref. 15).

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedule estimate reflects the results of a precedence network developed for the site decommissioning activities, i.e., a PERT (Program Evaluation and Review Technique) software package. The schedule forecast is current as of July 2001. The following assumptions were made in the development of the decommissioning schedule:

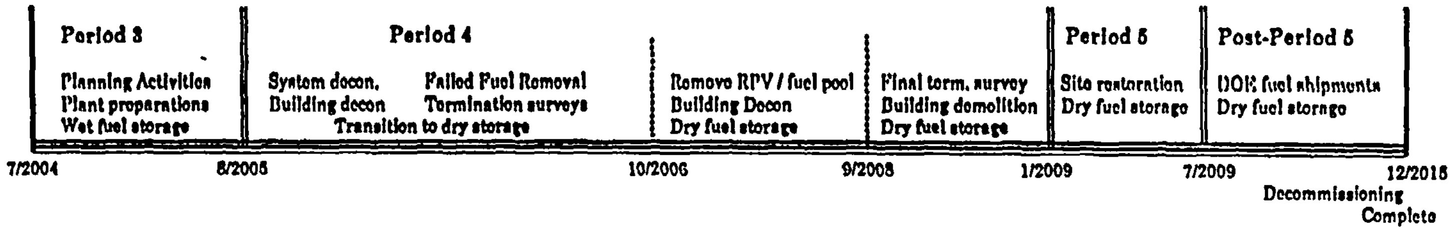
- Spent fuel will be transferred to the ISFSI by 2006. Final decommissioning activities will not begin before that time.
- All work (except vessel and internals removal) is performed during an 8-hour workday, 5 days per week, with no overtime.
- Vessel and internals removal activities are performed by using separate crews for different activities working on different shifts, with a corresponding backshift charge for the second shift.
- Multiple crews work parallel activities to the maximum extent possible, consistent with: optimum efficiency; adequate access for cutting, removal and laydown space; and the stringent safety measures necessary during demolition of heavy components and structures.
- For removal of plant systems by area, the areas with the longest removal durations on the critical path are considered to determine the duration.

4.2 PROJECT SCHEDULE

The period-dependent costs presented in the cost table in Appendix D are based upon the durations developed in the decommissioning project schedule. Durations are established between several milestones in each project period; these durations are used to establish a critical path for the entire project. In turn, the critical path duration for each period is used as the basis for determining the total costs for these period-dependent items.

A project timeline for the decommissioning alternative is included in this section as Figure 4.1.

FIGURE 4.1
DECOMMISSIONING TIMELINE
(not to scale)



__Key Assumptions__:

1. Decommissioning commences on July of 2004.
2. Initiation of selected decommissioning planning and regulatory activities occurs prior to plant shutdown.
3. Use of a Decommissioning Operations Contractor (DOC) in later Period 3 planning activities.
4. USDOE acceptance of spent fuel shipments is initiated in year 2010 and continues at the design rate of spent fuel acceptance for the final repository location.
5. GTCC wastes are removed from the plant site with the spent fuel.

__Critical Path Discussion__:

Following removal of all spent fuel to long term dry storage, the decommissioning critical path is assumed to be sequentially composed of removing the reactor vessel and spent fuel pool, decontamination of buildings, performing final site termination surveys, site restoration, and final spent fuel acceptance and removal by the USDOE.

5. RADIOACTIVE WASTE

5.1 GENERAL

A waste contractor will be employed to manage the handling, shipping, recycling and processing of radwaste. Due to the physical site layout limitations, and consistent with current decommissioning trends, a "rip and ship" philosophy will be utilized.

A facility will be constructed to support the efficient handling of radwaste. Structural demolition debris will be loaded onto intermodal containers and shipped by barge to a railhead in San Francisco or Portland for final shipment to Envirocare. The estimate also assumes that PG&E will purchase eight shipping trailers that are sized to meet the overland road shipping limitations of local highways. The cost of the facility and the trailers are included in the estimate.

A summary of the HBPP3 waste volumes is provided in Table 5.1.

5.2 CLASS A WASTE AND RECYCLING

All metallic radioactive waste will be shipped by the waste contractor to its recycling center. The estimate assumes that the total PG&E all-inclusive cost for recycling metallic waste is $2.00 per pound. This cost includes processing, shipping, and burial of contaminated waste. An additional $1.00 per pound recycling surcharge has been applied to specific components that have elevated alpha contamination. These components include radwaste tanks, main condenser, primary system components, and Class A portions of the reactor pressure vessel.

Class A dry active waste (DAW) will be processed and buried by the radioactive waste vendor at a delivered cost of $140 per cubic foot. This waste will be shipped by truck to Envirocare. Class A mixed waste will also be shipped and buried in the same manner.

All structural debris, including concrete, metal siding, and structural steel will be buried at a cost of $140 per cubic foot. This waste will be loaded onto barges, shipped to San Francisco or Portland, and rail-shipped to Envirocare. The material will be loaded on intermodal containers prior to barge shipment. Intermodals utilized for barge and subsequent rail shipment can be loaded to a 67,200 pound capacity. This is the preferred shipping alternative due to the local road limitations and the lack of accessible rail access. Contaminated soil will be disposed of similar to structural debris.

5.3 CLASS B WASTE

Class B waste will be transferred to the on-site waste contractor and shipped using a shielded truck to the Southwest Compact burial site or equivalent. The inclusive cost for Class B waste disposal is in accordance with the Barnwell fee schedule for Non-Atlantic compact generators. Class B waste includes spent resin waste from system decontamination and portions of the vessel shell and cladding in the beltline region.

5.4 CLASS C WASTE

Class C waste will be transferred to the on-site waste contractor and shipped using a shielded truck to the Southwest Burial Compact site or equivalent. The inclusive cost for Class C waste disposal is in accordance with the Barnwell fee schedule for Non-Atlantic compact generators. Class C waste includes control rod blades and portions of the reactor vessel internals.

5.5 GREATER THAN CLASS C WASTE

One additional canister and overpack will be purchased for the transport and dry storage of the GTCC waste. The waste will be stored consistent with the spent fuel and the DOE will assume ownership and disposal responsibility at a cost similar to the cost for disposal of spent fuel. GTCC waste includes those portions of the reactor vessel internals containing radioactivity levels in excess of Class C limits.

TABLE 5.1

DECOMMISSIONING WASTE DISPOSAL SUMMARY

	Waste Volume[3] (cubic feet)
Low Level Radioactive Waste[1]	
Class A[2]	81,767
Class B	1,321
Class C	423
GTCC	14
Subtotal	**83,524**
Miscellaneous Wastes	
Demolition Debris	240,775

Notes:

1 Radioactive waste is classified according to the requirements as delineated in Title 10 of the Code of Federal Regulations, Part 61.55.

2 Class A waste includes soil, discharge canal sediment and reactor caisson mixed waste.

3 Column may not add due to rounding.

6. RESULTS

The projected cost to decommission the Humboldt Bay Power Plant Unit 3 (2006 SAFSTOR), including costs spent to-date and the capital addition costs for the ISFSI is $300,374,371 (including an 21% contingency) in 2002 dollars, which includes $712,869 (17.3% contingency) for the CPUC's disallowances. The costs reflect the site-specific features of the HBPP3, the local cost of labor, the DOE's schedule for spent fuel receipt, and a projected cost for low-level radioactive waste disposal at the regional compact site. An analysis of the major activities contributing to the total cost for the decommissioning is provided in Table 6.1.

Staffing, including management, security, and health physics combine with the removal labor cost to represent the majority of the costs to decommission a nuclear station. This is a direct result of the labor-intensive nature of the decommissioning process, as well as the management controls required to ensure a safe and successful program. ISFSI installation, licensing and operating costs represent the next largest single item. Demolition debris disposal and low-level waste burial costs are indicative of the expense incurred in siting, developing, and licensing new disposal facilities, as well as the costs associated to meet the tighter standards being developed at the federal and local levels.

TABLE 6.1

SUMMARY OF DECOMMISSIONING COST CONTRIBUTORS

Work Category	Costs '02 (thousands $)	Percent of Total Costs (%)
Decontamination	2,354	0.8
Removal	23,608	7.9
Packaging	3,451	1.1
Shipping	2,023	0.7
Waste Processing & Recycling	9,096	3.0
Low Level Waste Burial	17,459	5.8
Demolition Debris Disposal	38,765	12.9
Staffing	77,388	25.8
Security	2,766	0.9
License Termination Survey	3,224	1.1
Insurance	664	0.2
Energy	527	0.2
NRC & EP Fees	2,167	0.7
NRC ISFSI Fees	2,925	1.0
ISFSI Capital, O&M, Fixed & Security	62,503	20.8
Non-ISFSI Expenditures	20,503	6.8
Equipment & Supplies	20,974	7.0
Engineering	9,980	3.3
Total	**300,374**	**100.0**

CPUC Disallowances		
Removal	311	43.6
Packaging	112	15.7
Shipping	4	0.5
Waste Processing	69	9.6
LLW Burial	117	16.5
Equipment & Supplies	100	14.1
Total	**713**	**100**

7. REFERENCES

1. U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72, "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, Federal Register Volume 53, Number 123 (p 24018+), June 27, 1988.

2. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," February 1995.

3. U.S. Code of Federal Regulations, Title 10, Parts 2, 50 and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, Federal Register Volume 61 (p39278+), July 29, 1996.

4. "Nuclear Waste Policy Act of 1982 and Amendments," U.S. Department of Energy's Office of Civilian Radioactive Management, 1982.

5. DOE/RW-0457, Acceptance Priority Ranking and Annual Capacity Report, U.S. Department of Energy's Office of Civilian Radioactive Waste Management, March 1995.

6. "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, January 15, 1986.

7. "U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 51, 70 and 72, "Radiological Criteria for License Termination", Federal Register Volume 62, Number 139, July 21, 1997.

8. SAFSTOR Decommissioning Plan for the Humboldt Bay Power Plant, Unit No. 3, July 1984.

9. Preliminary Shutdown Decommissioning Activities Report, PG&E letter HBL-98-002 dated February 27, 1998.

10 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

11. Department of Energy, "Decommissioning Handbook," DOE/EM-0142P, March 1994.

7. REFERENCES (continued)

12. R.S. Means, Building Construction Cost Data, 2002.

13. Project and Cost Engineers' Handbook, Second Edition, p. 239, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York.

14. U.S. Department of Transportation, Section 49 of the Code of Federal Regulations, "Transportation," Parts 173 through 178, 1996.

15. "Microsoft Project for 98," Microsoft Corporation, Redmond, WA.

APPENDIX A

WORK DIFFICULTY FACTOR ADJUSTMENTS

APPENDIX A

WORK DIFFICULTY FACTOR ADJUSTMENT

AREA	AREA DESCRIPTION	Access (%)	Respiratory Protection (%)	ALARA (%)	Protective Clothing (%)	Alpha Adjust. (%)
RB1-1	Emergency Condenser	20	25	10	30	50
RB1-2	Spent Fuel Pool	10	25	20	30	50
RB1-3	Cask Shipping Area	10	25	10	30	50
RB1-4	SFP Pumps/Filters	0	25	10	30	50
RB1-5	Laydown/Cask Washdown General Area	10	25	10	30	50
RB1-6	Reactor Vessel Cavity	50	50	100	100	50
RB2-1	El -2 Suppression Pool Cooler	10	25	10	30	0
RB2-2	Elev. -14, Manlift	10	25	10	30	0
RB2-3	Elev. -24, CRD Hydraulic Filters	20	25	10	30	50
RB2-4	Elev. -34, Suppression Pool Access Hatch	20	25	10	30	50
RB2-5	Elev. -44, CRD Piping	20	25	10	30	50
RB2-6	Elev. -54, CRD Trip Accumulators	20	25	10	30	50
RB2-7	Elev. -66, Caisson Sump, REDT	20	25	10	30	50
RB2-8	Suppression Pool - North	30	50	20	30	50
RB2-9	Suppression Pool - South	30	50	20	30	50
RB3-1	Cleanup Heat Exchangers	10	50	20	30	50
RB3-2	New Fuel Storage/Fuel Pool Coolers	20	25	20	30	50
RB4-1	Shutdown Heat Exchangers/Pumps	10	25	10	30	50
RB4-2	TBDT/Floor Drain Pumps	20	50	20	50	50
RB5-1	RFB Roof (HVAC only)	0	25	10	30	50
RB5-1	RFB Roof	0	25	10	30	0
TB1-1	Main Turbine	20	25	20	30	50
TB1-2	Main Generator/Exciter House	0	0	0	0	0
TB1-3	Hydrogen Yard	0	0	10	30	0
TB2-1	Main Condenser	20	25	20	30	50
TB2-2	Seal Oil Unit/Exciter Swgr	0	0	10	30	0
TB3-1	Reactor Feed/Lube Oil/Air Systems	0	25	20	30	50
TB3-2	Propane Engine Generator	0	0	0	0	0
TB3-3	2400/480V Transformers	0	0	10	0	0
TB4-1	Laundry Drain Tank/Pipe Tunnel	10	25	20	30	50
TB4-2	Pipe Gallery	30	50	40	50	50
TB5-1	Anion/Cation/Resin Tanks	10	25	20	30	0
TB5-2	Condensate Demineralizers	10	25	20	30	50
TB6-1	Air Ejector/Gland Seal Condenser	0	25	20	30	50
TB6-2	Vacuum Pump/Condensate Pumps	0	25	10	30	50

APPENDIX A

WORK DIFFICULTY FACTOR ADJUSTMENT (continued)

AREA	AREA DESCRIPTION	Access (%)	Respiratory Protection (%)	ALARA (%)	Protective Clothing (%)	Alpha Adjust. (%)
TB7-1	Main Control Room	0	25	10	30	0
TB7-2	Instr Repair/Counting Room/Vent Equip	0	0	10	0	0
TB7-3	Locker Room/Personnel Decon	0	0	10	0	0
TB7-4	Hot Lab	0	25	20	30	50
TB7-5	Demin Control Panel/RFB Access	0	0	10	0	0
TB7-6	Hot Lab Attic	10	25	10	30	0
TB7-7	RP Office/Count Room	0	0	0	0	0
RW1-1	RWB - Concentrator/Pumps/Filters	10	25	20	30	50
RW1-2	RWB - Waste Receiver/Hold Tanks	10	25	20	30	50
RW1-3	Radwaste Demineralizer	20	50	40	50	50
RW1-4	Concentrated Waste Tanks	20	25	20	30	50
RW1-5	Resin Disposal Tank	20	50	40	50	50
RW1-6	Upper Elevation - RWB	0	25	10	30	0
RW1-7	Packaged Radwaste Storage Bldg	0	0	10	0	0
RW1-8	Low Level Waste Storage Bldg	0	0	10	0	0
RW1-9	Solid Waste Vault	10	25	20	30	50
YD1-1	Main Transformers	0	0	0	0	0
YD1-2	CCW Heat Exchangers/Pumps	0	25	10	30	50
YD1-3	n/a			n/a		
YD1-4	n/a			n/a		
YD1-5	Intake Structure	0	0	0	0	0
YD2-1	Stack - Elev 0'0"	10	25	10	30	50
YD2-2	Stack - Elev. 12'0"	10	25	10	30	0
YD2-3	Stack - Elev. 26'0"	10	25	10	30	0
YD2-4	Condensate/Demin Water Storage Tank	0	25	10	30	50
YD2-5	Plant Exhaust Fans	0	25	20	30	50
YD2-6	Gaseous Radwaste Holdup Tunnel	20	50	20	- 30	50
HMS1-1	HMS Decon Area	0	25	10	30	50
HMS1-2	Calibration Lab	0	25	40	30	0

APPENDIX A

WORK DIFFICULTY FACTOR ADJUSTMENT (continued)

AREA	AREA DESCRIPTION	Access (%)	Respiratory Protection (%)	ALARA (%)	Protective Clothing (%)	Alpha Adjust. (%)
OTS1	Hydrogen Analyzer/MCC #14	0	0	0	0	0
OTS2	Moisture Skid/Sump Pump	0	0	0	0	0
OTS3	Jet Compressor/Recombiner/CG Bed	0	0	0	0	0
OTS4	Carbon Adsorbers	0	0	0	0	0
OTS5	Pipe Tunnel	0	0	0	0	0
OTS6	HEPA Filter (outside access only)	0	0	0	0	0
YARD	General Yard	0	0	0	0	0
RBP	Refueling Building - Embedded Piping	10	50	20	30	50
TBP	Turbine Building - Embedded Piping	10	50	20	30	50
YDP	Buried Yard Piping/Catch Basins, Etc.	0	0	10	0	50
RWP	Radwaste Building - Embedded Piping	10	50	20	30	50
HMSP	Hot Machine Shop - Embedded Piping	10	50	20	30	50

APPENDIX B

UNIT COST FACTOR DEVELOPMENT

APPENDIX B
UNIT COST FACTOR DEVELOPMENT

Example: Unit Factor for Removal of Contaminated Heat Exchanger < 3,000 lbs.

1. SCOPE

Heat exchangers weighing < 3,000 lbs. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the waste processing area.

2. CALCULATIONS

Activity Description	Critical Duration (minutes)
Install contamination controls, remove insulation, and mount pipe cutters	60
Disconnect inlet and outlet lines, cap openings	60
Rig for removal	30
Unbolt from mounts	30
Remove contamination controls	15
Remove heat exchanger, wrap in plastic, and send to packing area	60
Critical Duration	255

Work Adjustments (Work Difficulty Factors)

+Duration adjustment(s)	
Site-specific labor adjustment (50% of Critical Duration)	128
	383
+ Respiratory Protection (25% of Critical Duration)	96
+ Radiation/ALARA (10% of Critical Duration)	38
Adjusted Work Duration	517
+ Protective Clothing (30% of Adjusted Work Duration)	155
Productive Work Duration	672
+ Work break adjustment (8.33 % of Productive Work Duration)	56
Total Work Duration	728

***** Total Work Duration = 728 minutes or 12.133 hours *****

APPENDIX B
(continued)

3. LABOR REQUIRED

Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	3.00	12.133	$37.22	$1,354.77
Craftsmen	2.00	12.133	$45.37	$1,100.95
Foreman	1.00	12.133	$47.90	$581.17
General Foreman	0.25	12.133	$50.10	$151.97
Fire Watch	0.05	12.133	$37.22	$22.58
Health Physics Technician	1.00	12.133	$34.14	$414.22
Total Labor Cost				$3,625.66

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	
-Portable Pipe Cut/Milling Machine 1 @ $10.86/hr x 12.133 hrs {1}	$131.76
Consumables/Materials Costs	
-Blotting paper 50 @ $0.48 sq ft {2}	$24.00
-Plastic sheets/bags 50 @ $0.12/sq ft {3}	$6.00
-Slitting Saw 1 @ $34.69/hr x 1 hr {1}	$34.69
Subtotal Cost Of Equipment And Materials	$196.45
Overhead & Sales Tax On Equipment And Materials @ 17.00%	$33.40
Total Costs, Equipment & Material	$229.85

TOTAL COST: Removal of Contaminated Heat Exchanger <3000 Pounds: **$3,855.51**

Total Labor Cost:	$3,625.66
Total Equipment/Material Costs:	$229.85
Total Adjusted Exposure Man-Hours Incurred:	50.02
Total Craft Labor Man-Hours Required Per Unit:	88.57

APPENDIX B
(continued)

5. NOTES AND REFERENCES

- Work difficulty factors were developed in conjunction with the AIF (now NEI) program to standardize nuclear decommissioning cost estimates and are delineated in Volume 1, Chapter 5 of the "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

- References for equipment & consumables costs:

  1. The Wachs Companies, Quote dated 10/2001
  2. McMaster-Carr website on-line catalog
  3. R.S. Means (2002) Division 015 Section 602-0200 pg 17

- Material and consumable costs were adjusted using the regional indices for Eureka, California.

APPENDIX C

UNIT COST FACTOR LISTING
(Representative of Power Block Structures Only)

APPENDIX C

UNIT COST FACTOR LISTING
(Representative of Power Block Structures Only)

Unit Cost Factor	Cost/Unit($)
Removal of clean instrument and sampling tubing, $/linear foot	0.37
Removal of clean pipe 0.25 to 2 inches diameter, $/linear foot	3.98
Removal of clean pipe >2 to 4 inches diameter, $/linear foot	5.53
Removal of clean pipe >4 to 8 inches diameter, $/linear foot	10.67
Removal of clean pipe >8 to 14 inches diameter, $/linear foot	15.17
Removal of clean pipe >14 to 20 inches diameter, $/linear foot	21.56
Removal of clean pipe >20 to 36 inches diameter, $/linear foot	33.90
Removal of clean pipe >36 inches diameter, $/linear foot	41.46
Removal of clean valves >2 to 4 inches	70.96
Removal of clean valves >4 to 8 inches	106.68
Removal of clean valves >8 to 14 inches	151.73
Removal of clean valves >14 to 20 inches	215.61
Removal of clean valves >20 to 36 inches	338.97
Removal of clean valves >36 inches	414.60
Removal of clean pipe hangers for small bore piping	23.02
Removal of clean pipe hangers for large bore piping	84.97
Removal of clean pumps, <300 pound	194.69
Removal of clean pumps, 300-1000 pound	539.54
Removal of clean pumps, 1000-10,000 pound	1,973.43
Removal of clean pumps, >10,000 pound	3,807.43
Removal of clean pump motors, 300-1000 pound	228.02
Removal of clean pump motors, 1000-10,000 pound	823.13
Removal of clean pump motors, >10,000 pound	1,853.84
Removal of clean heat exchanger <3000 pound	1,152.29
Removal of clean heat exchanger >3000 pound	2,888.96

APPENDIX C
(continued)

Unit Cost Factor	Cost/Unit($)
Removal of clean tanks, <300 gallons	250.73
Removal of clean tanks, 300-3000 gallons	729.44
Removal of clean tanks, >3000 gallons, $/square foot surface area	6.08
Removal of clean electrical equipment, <300 pound	107.56
Removal of clean electrical equipment, 300-1000 pound	371.26
Removal of clean electrical equipment, 1000-10,000 pound	742.49
Removal of clean electrical equipment, >10,000 pound	1,613.08
Removal of clean electrical transformers < 30 tons	1,222.10
Removal of clean electrical transformers > 30 tons	3,226.15
Removal of clean standby diesel-generator, <100 kW	1,143.14
Removal of clean standby diesel-generator, 100 kW to 1 MW	2,553.17
Removal of clean standby diesel-generator, >1 MW	5,286.60
Removal of clean electrical cable tray, $/linear foot	9.15
Removal of clean electrical conduit, $/linear foot	3.84
Removal of clean mechanical equipment, <300 pound	107.56
Removal of clean mechanical equipment, 300-1000 pound	371.26
Removal of clean mechanical equipment, 1000-10,000 pound	742.49
Removal of clean mechanical equipment, >10,000 pound	1,613.08
Removal of clean HVAC equipment, <300 pound	107.56
Removal of clean HVAC equipment, 300-1000 pound	371.26
Removal of clean HVAC equipment, 1000-10,000 pound	742.49
Removal of clean HVAC equipment, >10,000 pound	1,613.08
Removal of clean HVAC ductwork, $/pound	0.42
Removal of contaminated instrument and sampling tubing, $/linear foot	1.24
Removal of contaminated pipe 0.25 to 2 inches diameter, $/linear foot	31.13

APPENDIX C
(continued)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated pipe >2 to 4 inches diameter, $/linear foot	44.47
Removal of contaminated pipe >4 to 8 inches diameter, $/linear foot	102.99
Removal of contaminated pipe >8 to 14 inches diameter, $/linear foot	164.10
Removal of contaminated pipe >14 to 20 inches diameter, $/linear foot	232.87
Removal of contaminated pipe >20 to 36 inches diameter, $/linear foot	338.04
Removal of contaminated pipe >36 inches diameter, $/linear foot	397.84
Removal of contaminated valves >2 to 4 inches	269.02
Removal of contaminated valves >4 to 8 inches	503.29
Removal of contaminated valves >8 to 14 inches	820.52
Removal of contaminated valves >14 to 20 inches	1,223.34
Removal of contaminated valves >20 to 36 inches	1,690.22
Removal of contaminated valves >36 inches	1,989.18
Removal of contaminated pipe hangers for small bore piping	97.19
Removal of contaminated pipe hangers for large bore piping	317.03
Removal of contaminated pumps, <300 pound	792.91
Removal of contaminated pumps, 300-1000 pound	1,836.16
Removal of contaminated pumps, 1000-10,000 pound	6,147.56
Removal of contaminated pumps, >10,000 pound	14,980.47
Removal of contaminated pump motors, 300-1000 pound	774.18
Removal of contaminated pump motors, 1000-10,000 pound	2,391.93
Removal of contaminated pump motors, >10,000 pound	5,395.80
Removal of contaminated turbine-driven pumps < 10,000 pounds	7,513.22
Removal of contaminated turbine-driven pumps > 10,000 pounds	17,129.92
Removal of contaminated heat exchanger <3000 pound	3,855.51
Removal of contaminated heat exchanger >3000 pound	10,699.94

APPENDIX C
(continued)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated feedwater heater/deaerator	24,780.54
Removal of contaminated moisture separator/reheater	62,545.00
Removal of contaminated tanks, <300 gallons	1,313.08
Removal of contaminated tanks, >300 gallons, $/square foot	36.94
Removal of contaminated electrical equipment, <300 pound	617.33
Removal of contaminated electrical equipment, 300-1000 pound	1,490.62
Removal of contaminated electrical equipment, 1000-10,000 pound	2,866.71
Removal of contaminated electrical equipment, >10,000 pound	5,438.34
Removal of contaminated electrical cable tray, $/linear foot	28.77
Removal of contaminated electrical conduit, $/linear foot	25.05
Removal of contaminated mechanical equipment, <300 pound	666.48
Removal of contaminated mechanical equipment, 300-1000 pound	1,597.83
Removal of contaminated mechanical equipment, 1000-10,000 pound	3,076.96
Removal of contaminated mechanical equipment, >10,000 pound	5,438.34
Removal of contaminated HVAC equipment, <300 pound	666.48
Removal of contaminated HVAC equipment, 300-1000 pound	1,597.83
Removal of contaminated HVAC equipment, 1000-10,000 pound	3,076.96
Removal of contaminated HVAC equipment, >10,000 pound	5,438.34
Removal of contaminated HVAC ductwork, $/pound	2.75
Removal/plasma arc cut of contaminated thin metal components, $/linear in.	3.23
Additional decontamination of surface by washing, $/square foot	6.67
Additional decontamination of surfaces by hydrolasing, $/square foot	28.29
Decontamination rig hook-up and flush	5,641.45
Chemical flush of components/systems, $/gallon	11.65
Removal of standard reinforced concrete, $/cubic yard	63.68

APPENDIX C
(continued)

Unit Cost Factor	Cost/Unit($)
Removal of grade slab concrete, $/cubic yard	185.69
Removal of clean concrete floors, $/cubic yard	261.45
Removal of sections of clean concrete floors, $/cubic yard	832.30
Removal of clean heavily rein concrete w/#9 rebar, $/cubic yard	177.20
Removal of contaminated heavily rein concrete w/#9 rebar, $/cubic yard	465.09
Removal of clean heavily rein concrete w/#18 rebar, $/cubic yard	233.74
Removal of contaminated heavily rein concrete w/#18 rebar, $/cubic yard	1,713.05
Removal heavily rein concrete w/#18 rebar & steel embedments, $/cu yd	334.25
Removal of below-grade suspended floors, $/square foot	225.18
Removal of clean monolithic concrete structures, $/cubic yard	641.19
Removal of contaminated monolithic concrete structures, $/cu yd	1,713.29
Removal of clean foundation concrete, $/cubic yard	546.25
Removal of contaminated foundation concrete, $/cubic yard	1,593.72
Explosive demolition of bulk concrete, $/cubic yard	24.63
Removal of clean hollow masonry block wall, $/cubic yard	71.56
Removal of contaminated hollow masonry block wall, $/cubic yard	243.94
Removal of clean solid masonry block wall, $/cubic yard	71.56
Removal of contaminated solid masonry block wall, $/cubic yard	243.94
Backfill of below-grade voids, $/cubic yard	17.08
Removal of subterranean tunnels/voids, $/linear foot	125.67
Placement of concrete for below-grade voids, $/cubic yard	99.68
Excavation of clean material, $/cubic yard	2.91
Excavation of contaminated material, $/cubic yard	36.03
Excavation of submerged concrete rubble, $/cubic yard	11.55
Removal of clean concrete rubble, $/cubic yard	80.20

APPENDIX C
(continued)

Unit Cost Factor	Cost/Unit($)
Removal of contaminated concrete rubble, $/cubic yard	28.99
Removal of building by volume, $/cubic foot	0.24
Removal of clean building metal siding, $/square foot	1.19
Removal of contaminated building metal siding, $/square foot	4.04
Removal of standard asphalt roofing, $/square foot	1.88
Removal of transite panels, $/square foot	1.98
Scarifying contaminated concrete surfaces (drill & spall)	12.09
Scabbling contaminated concrete floors, $/square foot	7.16
Scabbling contaminated concrete walls, $/square foot	7.64
Scabbling contaminated ceilings, $/square foot	68.72
Scabbling structural steel, $/square foot	5.72
Removal of clean overhead cranes/monorails < 10 ton capacity	471.83
Removal of contaminated overhead cranes/monorails < 10 ton capacity	1,474.45
Removal of clean overhead cranes/monorails >10-50 ton capacity	1,130.93
Removal of contaminated overhead cranes/monorails >10-50 ton capacity	3,535.28
Removal of polar cranes > 50 ton capacity, each	4,716.04
Removal of gantry cranes > 50 ton capacity, each	20,161.42
Removal of structural steel, $/pound	0.32
Removal of clean steel floor grating, $/square foot	2.74
Removal of contaminated steel floor grating, $/square foot	8.77
Removal of clean free-standing steel liner, $/square foot	9.12
Removal of contaminated free-standing steel liner, $/square foot	29.21
Removal of clean concrete-anchored steel liner, $/square foot	4.56
Removal of contaminated concrete-anchored steel liner, $/square foot	33.94
Placement of scaffolding in clean areas, $/square foot	13.54

APPENDIX C
(continued)

Unit Cost Factor	Cost/Unit($)
Placement of scaffolding in contaminated areas, $/square foot	21.41
Landscaping w/ topsoil, $/acre	15,848.42
Cost of LSA box & preparation for use	1,445.57
Cost of LSA drum & preparation for use	188.29
Cost of cask liner for CNSI 14-195 cask	9,739.76
Cost of cask liner for CNSI 8-120A cask (resins)	8,409.88
Cost of cask liner for CNSI 8-120A cask (filters)	8,409.88
Decontamination of surfaces with vacuuming, $/square foot	1.55

APPENDIX D

HUMBOLDT BAY 2006 SAFSTOR DECOMMISSIONING COST

APPENDIX D
HUMBOLDT BAY 2006 SAFSTOR
DECOMMISSIONING COST
(Thousands of 2002 dollars)

ID Number	Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
PERIOD 2																
	HBPP Unit #3 1996 Completed Projects	-	-	-	-	-	1,678	-	1,678	1,678	-	-	-	-	-	-
	HBPP Unit #3 1997 Completed Projects	-	-	-	-	-	8,663	-	8,663	8,663	-	-	-	-	-	-
	HBPP Unit #3 1998 Completed Projects	-	-	-	-	-	5,574	-	5,574	5,574	-	-	-	-	-	-
	HBPP Unit #3 1999 Completed Projects	-	-	-	-	-	724	-	724	724	-	-	-	-	-	-
	HBPP Unit #3 2000 Completed Projects	-	-	-	-	-	84	-	84	84	-	-	-	-	-	-
	ISFSI Design & Licensing 1998	-	-	-	-	-	344	-	344	344	-	-	-	-	-	-
	ISFSI Design & Licensing 1999	-	-	-	-	-	1,994	-	1,994	1,994	-	-	-	-	-	-
	ISFSI Design & Licensing 2000	-	-	-	-	-	2,264	-	2,264	2,264	-	-	-	-	-	-
	ISFSI Design & Licensing 2001	-	-	-	-	-	268	-	268	268	-	-	-	-	-	-
	ISFSI Design & Licensing 2002	-	-	-	-	-	3,492	848	4,340	4,340	-	-	-	-	-	-
	ISFSI Design & Licensing 2003	-	-	-	-	-	312	76	388	388	-	-	-	-	-	-
	ISFSI Design & Licensing 2004	-	-	-	-	-	724	176	900	900	-	-	-	-	-	-
	Radiological Characterization	-	-	-	-	-	477	133	610	610	-	-	-	-	-	-
	Reactor Vessel Activation Analysis	-	-	-	-	-	85	15	100	100	-	-	-	-	-	-
	Develop Cost, Schedule & Work Controls	-	-	-	-	-	200	-	200	200	-	-	-	-	-	-
	Develop "Level 2" Decommissioning Schedule	-	-	-	-	-	175	-	175	175	-	-	-	-	-	-
	Develop Site Facilities & Staffing Plan	-	-	-	-	-	170	-	170	170	-	-	-	-	-	-
	Asbestos Removal	-	-	-	-	-	1,062	318	1,380	1,380	-	-	-	-	-	-
	LLW Management Plan	-	-	-	-	-	467	118	585	585	-	-	-	-	-	-
	Decom Demonstration Project	-	-	-	-	-	321	79	400	400	-	-	-	-	-	-
	Decommissioning Design Basis	-	-	-	-	-	60	-	60	60	-	-	-	-	-	-
	Revise Licensing Basis	-	-	-	-	-	100	-	100	100	-	-	-	-	-	-
	Total	-	-	-	-	-	29,240	1,763	31,003	31,003	-	-	-	-	-	-
PERIOD 3																
1	Perform detailed rad survey	-	-	-	-	-	-	-	Note 1	-	-	-	-	-	-	-
2	Review plant dwgs & specs.	-	-	-	-	-	321	48	369	369	-	-	-	-	-	-
3	End product description	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-
4	Detailed by-product inventory	-	-	-	-	-	8	1	9	9	-	-	-	-	-	-
5	Define major work sequence	-	-	-	-	-	375	56	431	431	-	-	-	-	-	-
6	Perform SER and EA	-	-	-	-	-	310	47	357	357	-	-	-	-	-	-
7	Perform Site-Specific Cost Study	-	-	-	-	-	500	75	575	575	-	-	-	-	-	-
8	Prepare/submit License Termination Plan	-	-	-	-	-	166	25	190	190	-	-	-	-	-	-
9	Receive NRC approval of termination plan	-	-	-	-	-	-	-	Note 2	-	-	-	-	-	-	-
Activity Specifications																
10.1	Re-activate plant & temporary facilities	-	-	-	-	-	652	98	750	675	75	-	-	-	-	-
10.2	Plant systems	-	-	-	-	-	295	44	339	305	34	-	-	-	-	-
10.3	Reactor internals	-	-	-	-	-	660	99	759	759	-	-	-	-	-	-
10.4	Reactor vessel	-	-	-	-	-	600	90	690	690	-	-	-	-	-	-
10.5	Sacrificial shield	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-
10.6	Moisture separators/reheaters	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-
10.7	Reinforced concrete	-	-	-	-	-	160	24	184	166	18	-	-	-	-	-
10.8	Turbine & condenser	-	-	-	-	-	417	63	479	479	-	-	-	-	-	-
10.9	Pressure suppression structure	-	-	-	-	-	200	30	230	230	-	-	-	-	-	-
10.10	Primary containment	-	-	-	-	-	160	24	184	184	-	-	-	-	-	-
10.11	Plant structures & buildings	-	-	-	-	-	190	29	219	219		-	-	-	-	-
10.12	Waste management	-	-	-	-	-	109	16	125	125	-	-	-	-	-	
10.13	Facility & site closeout	-	-	-	-	-	90	14	104	52	52	-	-	-	-	
10	Total	-	-	-	-	-	3,682	552	4,235	4,056	179	-	-	-	-	
Planning & Site Preparations																
11	Prepare dismantling sequence	-	-	-	-	-	240	36	276	276	-	-	-	-	-	-
12	Plant prep. & temp. svces	-	-	-	-	-	2,219	333	2,552	2,552	-	-	-	-	-	
13	Design water clean-up system	-	-	-	-	-	140	21	161	161	-	-	-	-		
14	Rigging/CCEs/tooling/etc.	-	-	-	-	-	1,300	195	1,495	1,495	-		-	-	-	
15	Procure casks/liners & containers	-	-	-	-	-	123	18	141	141	-	-	-			

APPENDIX D
HUMBOLDT BAY 2006 SAFSTOR
DECOMMISSIONING COST
(Thousands of 2002 dollars)

ID Number	Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
Detailed Work Procedures																
16.1	Plant systems	-	-	-	-	-	473	71	544	490	54	-	-	-	-	-
16.2	Vessel head	-	-	-	-	-	24	4	28	28	-	-	-	-	-	-
16.3	Reactor internals	-	-	-	-	-	400	60	460	460	-	-	-	-	-	-
16.4	Remaining buildings	-	-	-	-	-	135	20	155	39	116	-	-	-	-	-
16.5	CRD housings & ICI tubes	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-
16.6	Incore instrumentation	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-
16.7	Removal primary containment	-	-	-	-	-	200	30	230	230	-	-	-	-	-	-
16.8	Reactor vessel	-	-	-	-	-	363	54	417	417	-	-	-	-	-	-
16.9	Facility closeout	-	-	-	-	-	120	18	138	69	69	-	-	-	-	-
16.10	Sacrificial shield	-	-	-	-	-	120	18	138	138	-	-	-	-	-	-
16.11	Reinforced concrete	-	-	-	-	-	100	15	115	58	58	-	-	-	-	-
16.12	Turbine & condensers	-	-	-	-	-	270	41	311	311	-	-	-	-	-	-
16.13	Moisture separators & reheaters	-	-	-	-	-	54	8	62	62	-	-	-	-	-	-
16.14	Radwaste building	-	-	-	-	-	127	19	146	131	15	-	-	-	-	-
16.15	Reactor building	-	-	-	-	-	127	19	146	131	15	-	-	-	-	-
16	Total	-	-	-	-	-	2,713	407	3,120	2,793	327	-	-	-	-	-
17	Asbestos removal program	-	98	39	1	349	-	116	601	601	-	-	-	-	-	2,406
Subtotal Period 3 Activity Costs		-	98	39	1	349	12,197	1,945	14,628	14,122	506	-	-	-	-	2,406
Period 3 Additional Costs																
18	Additional Support Facilities	-	-	-	-	-	1,894	284	2,178	2,178	-	-	-	-	-	-
19	Mixed Waste Disposal	-	2	6	3	-	260	41	312	312	-	207	-	-	-	66
Period 3 Undistributed Costs																
1	DOC staff relocation expenses	-	1,441	-	-	-	-	216	1,658	1,658	-	-	-	-	-	-
2	Insurance	-	-	-	-	-	213	21	234	234	-	-	-	-	-	-
3	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Health physics supplies	-	228	-	-	-	-	57	285	285	-	-	-	-	-	-
5	Heavy equipment rental	-	431	-	-	-	-	65	495	495	-	-	-	-	-	-
6	Disposal of DAW generated	-	-	34	1	28	-	10	73	73	-	199	-	-	-	540
7	Plant energy budget	-	-	-	-	-	133	20	153	153	-	-	-	-	-	-
8	NRC Fees	-	-	-	-	-	314	31	346	346	-	-	-	-	-	-
9	Emergency Planning Fees	-	-	-	-	-	118	12	130	130	-	-	-	-	-	-
10	Site Security	-	-	-	-	-	964	145	1,108	1,108	-	-	-	-	-	-
11	Fabricate Casks & Construct ISFSI	-	-	-	-	-	13,616	4,153	17,769	17,769	-	-	-	-	-	-
12	Rebuild Refueling Bldg Crane	-	-	-	-	-	1,008	151	1,159	1,159	-	-	-	-	-	-
Subtotal Undistributed Costs Period 3		-	2,100	34	1	28	16,367	4,881	23,411	23,411	-	199	-	-	-	540
Staff Costs																
	DOC Staff Cost	-	-	-	-	-	1,739	261	2,000	2,000	-	-	-	-	-	-
	Utility Staff Cost	-	-	-	-	-	14,285	2,143	16,427	16,427	-	-	-	-	-	-
TOTAL PERIOD 3 COST		-	2,200	79	4	378	48,741	9,555	58,955	58,450	506	406	-	-	-	3,012
PERIOD 4																
20	Remove spent fuel racks	40	8	12	2	193	66	81	402	402	-	1,377	-	-	-	1,068
21	Fuel Pool Cleanup	-	-	-	-	-	348	52	400	400	-	-	-	-	-	750
Nuclear Steam Supply System Removal																
22.1	CRDMs & ICIs Removal	3	22	46	4	352	-	100	528	528	-	782	-	-	-	620
22.2	Reactor Vessel Internals	8	1,893	1,233	127	720	-	2,124	6,106	6,106	-	506	-	423	-	13,470
22.3	Reactor Vessel	8	3,443	294	97	500	-	2,934	7,276	7,276	-	296	626	-	-	10,776
22	Totals	19	5,358	1,574	228	1,572	-	5,158	13,910	13,910	-	1,575	626	423	-	24,066
Removal of Major Equipment																
23	Main Turbine/Generator	-	72	-	-	-	1,251	206	1,528	1,528	-	-	-		-	1,548
24	Main Condensers	-	21	87	27	1,175	989	460	2,760	2,760	-	8,306	-	-	-	479

APPENDIX D
HUMBOLDT BAY 2006 SAFSTOR
DECOMMISSIONING COST
(Thousands of 2002 dollars)

ID Number	Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
Disposal of Plant Systems																
25.1	HMS1-1	-	40	-	-	-	28	14	82	82	-	-	-	-	-	980
25.2	HMS1-2	-	4	-	-	-	2	1	8	8	-	-	-	-	-	99
25.3	HMSP	-	6	-	-	-	4	2	12	12	-	-	-	-	-	135
25.4	OTS-1	-	12	-	-	-	14	5	31	31	-	-	-	-	-	272
25.5	OTS-2	-	11	-	-	-	10	4	25	25	-	-	-	-	-	235
25.6	OTS-3	-	16	-	-	-	30	8	54	54	-	-	-	-	-	353
25.7	OTS-4	-	10	-	-	-	9	4	24	24	-	-	-	-	-	229
25.8	OTS-5	-	8	-	-	-	4	2	14	14	-	-	-	-	-	160
25.9	OTS-6	-	2	-	-	-	1	1	3	3	-	-	-	-	-	33
25.10	RB1-1	-	43	-	-	-	52	19	114	114	-	-	-	-	-	1,029
25.11	RB1-2	-	20	-	-	-	15	7	42	42	-	-	-	-	-	470
25.12	RB1-3	-	16	-	-	-	5	5	25	25	-	-	-	-	-	396
25.13	RB1-4	-	72	-	-	-	24	22	118	118	-	-	-	-	-	1,709
25.14	RB1-5	-	97	-	-	-	38	30	165	165	-	-	-	-	-	2,340
25.15	RB1-6	-	401	-	-	-	201	130	732	732	-	-	-	-	-	9,744
25.16	RB2-1	-	56	-	-	-	23	17	96	96	-	-	-	-	-	1,293
25.17	RB2-2	-	64	-	-	-	70	27	161	161	-	-	-	-	-	1,496
25.18	RB2-3	-	84	-	-	-	14	23	121	121	-	-	-	-	-	1,993
25.19	RB2-4	-	33	-	-	-	6	9	48	48	-	-	-	-	-	796
25.20	RB2-5	-	136	-	-	-	82	46	265	265	-	-	-	-	-	3,237
25.21	RB2-6	-	216	-	-	-	27	58	301	301	-	-	-	-	-	5,147
25.22	RB2-7	-	205	-	-	-	42	57	304	304	-	-	-	-	-	4,859
25.23	RB2-8	-	225	-	-	-	167	81	473	473	-	-	-	-	-	5,268
25.24	RB2-9	-	225	-	-	-	167	81	473	473	-	-	-	-	-	5,266
25.25	RB3-1	-	64	-	-	-	38	22	124	124	-	-	-	-	-	1,513
25.26	RB3-2	-	11	-	-	-	6	4	21	21	-	-	-	-	-	266
25.27	RB4-1	-	50	-	-	-	49	20	118	118	-	-	-	-	-	1,134
25.28	RB4-2	-	36	-	-	-	15	11	61	61	-	-	-	-	-	831
25.29	RB5-1	-	27	-	-	-	8	8	42	42	-	-	-	-	-	658
25.30	RB5-1 (HVAC Scope)	-	29	-	-	-	22	10	61	61	-	-	-	-	-	632
25.31	RBP	-	362	-	-	-	5	91	458	458	-	-	-	-	-	8,751
25.32	RW1-1	-	186	-	-	-	50	54	290	290	-	-	-	-	-	4,463
25.33	RW1-2	-	200	-	-	-	59	59	318	318	-	-	-	-	-	4,631
25.34	RW1-3	-	4	-	-	-	1	1	6	6	-	-	-	-	-	92
25.35	RW1-4	-	47	-	-	-	32	16	95	95	-	-	-	-	-	1,079
25.36	RW1-5	-	55	-	-	-	24	17	96	96	-	-	-	-	-	1,278
25.37	RW1-6	-	42	-	-	-	30	15	88	88	-	-	-	-	-	965
25.38	RW1-7	-	15	-	-	-	7	5	27	27	-	-	-	-	-	342
25.39	RW1-8	-	4	-	-	-	2	1	7	7	-	-	-	-	-	96
25.40	RW1-9	-	4	-	-	-	1	1	6	6	-	-	-	-	-	100
25.41	RWP	-	127	-	-	-	2	32	161	161	-	-	-	-	-	3,090
25.42	TB1-1	-	82	-	-	-	63	30	175	175	-	-	-	-	-	2,119
25.43	TB1-2	-	7	-	-	-	492	75	574	574	-	-	-	-	-	160
25.44	TB1-3	-	25	-	-	-	25	10	60	60	-	-	-	-	-	577
25.45	TB2-1	-	357	-	-	-	267	129	753	753	-	-	-	-	-	8,425
25.46	TB2-2	-	64	-	-	-	47	23	134	134	-	-	-	-	-	1,480
25.47	TB3-1	-	385	-	-	-	263	136	784	784	-	-	-	-	-	9,190
25.48	TB3-2	-	13	-	-	-	19	6	38	38	-	-	-	-	-	281
25.49	TB3-3	-	27	-	-	-	0	7	34	34	-	-	-	-	-	220
25.50	TB4-1	-	106	-	-	-	51	34	191	191	-	-	-	-	-	2,448
25.51	TB4-2	-	436	-	-	-	150	131	716	716	-	-	-	-	-	10,423
25.52	TB5-1	-	97	-	-	-	19	27	144	144	-	-	-	-	-	2,311
25.53	TB5-2	-	61	-	-	-	19	18	98	98	-	-	-	-	-	1,455
25.54	TB6-1	-	69	-	-	-	47	24	141	141	-	-	-	-	-	1,638
25.55	TB6-2	-	82	-	-	-	48	28	157	157	-	-	-	-	-	1,928
25.56	TB7-1	-	83	-	-	-	76	32	192	192	-	-	-	-		1,974
25.57	TB7-2	-	14	-	-	-	14	6	35	35	-	-	-	-	-	303
25.58	TB7-3	-	10	-	-	-	12	4	26	26	-	-	-	-	-	203
25.59	TB7-4	-	9	-	-	-	2	3	14	14	-	-	-	-	-	236
25.60	TB7-5	-	20	-	-	-	24	8	52	52	-	-	-	-	-	451
25.61	TB7-6	-	36	-	-	-	29	13	78	78	-	-	-	-	-	756
25.62	TB7-7	-	26	-	-	-	10	8	45	45	-	-	-	-	-	624

APPENDIX D
HUMBOLDT BAY 2006 SAFSTOR
DECOMMISSIONING COST
(Thousands of 2002 dollars)

ID Number	Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
Disposal of Plant Systems (continued)																
25.63	TBP	-	660	-	-	-	9	166	835	835	-	-	-	-	-	15,984
25.64	YARD	-	3	-	-	-	0	1	4	4	-	-	-	-	-	83
25.65	YD1-1	-	48	-	-	-	231	47	326	326	-	-	-	-	-	490
25.66	YD1 2	-	75	-	-	-	68	29	171	171	-	-	-	-	-	1,711
25.67	YD1-5	-	7	-	-	-	7	3	17	17	-	-	-	-	-	153
25.68	YD2-1	-	35	-	-	-	8	10	53	53	-	-	-	-	-	832
25.69	YD2-2	-	14	-	-	-	8	5	27	27	-	-	-	-	-	320
25.70	YD2-3	-	5	-	-	-	6	2	14	14	-	-	-	-	-	121
25.71	YD2-4	-	82	-	-	-	51	28	162	162	-	-	-	-	-	1,885
25.72	YD2-5	-	199	-	-	-	137	70	407	407	-	-	-	-	-	4,538
25.73	YD2-6	-	142	-	-	-	77	47	266	266	-	-	-	-	-	3,387
25.74	YDP	-	167	-	-	-	122	60	350	350	-	-	-	-	-	2,543
25	Totals	-	6,711	-	-	-	3,783	2,245	12,740	12,740	-	-	-	-	-	158,723
26	Erect scaffolding for systems removal	-	279	0	0	11	26	76	393	393	-	25	-	-	-	1,738
Decontamination of Site Buildings																
27.1	HMS	18	-	7	3	65	-	26	119	119	-	461	-	-	-	305
27.2	RB1	379	250	108	43	1,016	532	603	2,932	2,932	-	7,009	-	-	-	13,924
27.3	RB2	590	635	21	8	214	488	584	2,539	2,539	-	1,298	-	-	-	28,690
27.4	RB3	15	3	3	1	29	8	17	76	76	-	201	-	-	-	341
27.5	RB4	12	2	3	1	26	8	15	67	67	-	179	-	-	-	282
27.6	RW1	57	1	13	5	121	1	61	259	259	-	847	-	-	-	1,053
27.7	TB1	5	2	1	1	13	5	7	34	34	-	88	-	-	-	134
27.8	TB2	29	1	6	3	60	3	31	134	134	-	425	-	-	-	553
27.9	TB3	11	1	2	1	23	2	12	51	51	-	160	-	-	-	209
27.10	TB4	15	3	4	2	36	9	19	86	86	-	247	-	-	-	337
27.11	TB5	8	-	2	1	17	-	8	35	35	-	119	-	-	-	139
27.12	TB6	7	-	2	1	15	-	8	32	32	-	110	-	-	-	123
27.13	TB7	11	-	4	1	33	-	14	63	63	-	236	-	-	-	186
27.14	YD1	7	-	2	1	16	-	8	34	34	-	117	-	-	-	130
27.15	YD2	43	-	12	5	109	-	51	219	219	-	776	-	-	-	767
27.16	RBS-1 (Refuel Bldg Roof)	23	-	5	2	48	-	24	100	100	-	330	-	-	-	417
27	Totals	1,230	897	194	78	1,839	1,054	1,488	6,779	6,779	-	12,604	-	-	-	47,588
Demolition of Remaining Site Buildings (Note 3)																
28.1	Contaminated Equipment Storage	-	7	-	8	280	-	44	339	339	-	-	-	-	-	104
28.2	Fuel Pool Tremie Removal	-	72	-	64	2,094	-	334	2,563	2,563	-	-	-	-	-	866
28.3	Gas Stack	-	29	-	67	2,221	-	348	2,665	2,665	-	-	-	-	-	513
28.4	Hot Machine Shop & Calibration	-	18	-	19	641	-	102	780	780	-	-	-	-	-	296
28.5	New Off Gas Vault	-	79	-	154	5,088	-	798	6,119	6,119	-	-	-	-	-	1,294
28.6	Radwaste Treatment	-	123	-	97	3,193	-	512	3,925	3,925	-	-	-	-	-	1,702
28.7	Refueling	-	352	-	271	8,927	-	1,433	10,983	10,983	-	-	-	-	-	5,175
28.8	Solid Waste Vault	-	5	-	5	155	-	25	189	189	-	-	-	-	-	67
28.9	Turbine	-	387	-	312	10,284	-	1,647	12,630	12,630	-	-	-	-	-	5,536
28.10	Yard Structures	-	32	-	25	827	-	133	1,017	1,017	-	-	-	-	-	565
28	Totals	-	1,104	-	1,023	33,709	-	5,375	41,210	41,210	-	-	-	-	-	16,118
29	Utility license termination survey	-	-	-	-	-	2,232	670	2,901	2,901	-	-	-	-	-	37,171
30	ORISE confirmatory survey	-	-	-	-	-	111	33	144	144	-	-	-	-	-	-
31	Terminate license	-	-	-	-	-	-	-	Note 2	-	-	-	-	-	-	-

APPENDIX D
HUMBOLDT BAY 2006 SAFSTOR
DECOMMISSIONING COST
(Thousands of 2002 dollars)

ID Number	Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
	Period 4 Additional Costs															
32	Decon and Remediate Intake and Discharge	174	1,582	679	167	3,620	-	1,480	7,702	7,702	-	25,855	-	-	-	29,368
33	Contaminated Soil Removal	-	10	-	71	3,080	-	783	3,945	3,945	-	22,000	-	-	-	139
34	Caisson Mixed Waste Removal	-	68	41	8	279	-	109	505	505	-	1,419	-	-	-	1,390
35	Discharge Piping	28	342	106	32	974	-	359	1,841	1,841	-	6,958	-	-	-	4,977
36	Replacement of Drains and Catch Basins	-	51	-	-	-	-	8	59	59	-	-	-	-	-	651
	Subtotal Period 4 Activity Costs	1,490	18,504	2,693	1,637	46,452	9,859	18,584	97,220	97,220	-	80,209	626	423	-	324,575
	Period 4 Undistributed Costs															
1	Decon equipment	689	-	-	-	-	-	103	793	793	-	-	-	-	-	-
2	Decon supplies	332	-	-	-	-	-	83	415	415	-	-	-	-	-	-
3	DOC staff relocation expenses	-	1,441	-	-	-	-	216	1,658	1,658	-	-	-	-	-	-
4	Process liquid waste	79	-	48	92	313	-	137	669	669	-	-	695	-	-	247
5	Insurance	-	-	-	-	-	365	37	402	402	-	-	-	-	-	-
6	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Health physics supplies	-	1,603	-	-	-	-	401	2,003	2,003	-	-	-	-	-	-
8	Heavy equipment rental	-	6,184	-	-	-	-	926	7,111	6,400	711	-	-	-	-	-
9	Small tool allowance	-	198	-	-	-	-	30	227	205	23	-	-	-	-	-
10	Pipe cutting equipment	-	911	-	-	-	-	137	1,048	1,048	-	-	-	-	-	-
11	Disposal of DAW generated	-	-	101	2	81	-	31	215	215	-	581	-	-	-	1,579
12	Decommissioning Equipment Disposition	-	-	9	4	80	480	93	666	666	-	572	-	-	-	778
13	Plant energy budget	-	-	-	-	-	316	47	363	327	36	-	-	-	-	-
14	NRC Fees	-	-	-	-	-	545	55	600	600	-	-	-	-	-	-
15	Emergency Planning Fees	-	-	-	-	-	344	34	379	379	-	-	-	-	-	-
16	Site Security	-	-	-	-	-	1,420	213	1,633	1,633	-	-	-	-	-	-
17	LLRW Processing Equipment	-	-	-	-	-	1,001	150	1,151	1,151	-	-	-	-	-	-
18	ISFSI O&M	-	-	-	-	-	60	18	78	78	-	-	-	-	-	-
19	ISFSI Fixed Costs	-	-	-	-	-	1,188	356	1,544	1,544	-	-	-	-	-	-
20	ISFSI Security	-	-	-	-	-	2,292	687	2,979	2,979	-	-	-	-	-	-
21	NRC ISFSI Fees	-	-	-	-	-	549	165	714	714	-	-	-	-	-	-
22	Fabricate Casks & Construct ISFSI	-	-	-	-	-	8,376	2,555	10,931	10,931	-	-	-	-	-	-
	Subtotal Undistributed Costs Period 4	1,100	10,336	158	99	474	18,938	6,475	35,579	34,809	770	1,152	695	-	-	2,604
	Staff Costs															
	DOC Staff Cost	-	-	-	-	-	9,888	1,483	11,371	11,371	-	-	-	-	-	-
	Utility Staff Cost	-	-	-	-	-	36,785	5,518	42,303	42,303	-	-	-	-	-	-
	TOTAL PERIOD 4	2,590	28,840	2,851	1,736	48,926	73,469	32,060	188,472	185,702	770	81,361	1,321	423	-	327,179
	PERIOD 5															
	Site Closeout Activities															
37	Backfill Site	-	222	-	-	-	-	33	256	-	256	-	-	-	-	1,003
38	Grade & landscape site	-	24	-	-	-	-	4	27	-	27	-	-	-	-	79
39	Final report to NRC	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-
	Period 5 Additional Costs															
40	Purchase Impact Limiters	-	-	-	-	-	1,800	540	2,340	2,340	-	-	-	-	-	-
41	Transferal of spent fuel to DOE	-	-	-	-	-	400	120	520	520	-	-	-	-	-	-
42	Vessel & Internals GTCC Disposal	-	-	-	-	141	-	21	162	162	-	-	-	-	14	-
43	ISFSI Decommissioning	-	675	-	-	-	-	203	878	878	-	-	-	-	-	3,221
	Subtotal Period 5 Activity Costs	-	921	-	-	141	2,356	944	4,362	4,079	283	-	-	-	14	4,303
	Period 5 Undistributed Costs															
1	Insurance	-	-	-	-	-	25	2	27	27	-	-	-	-	-	-
2	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Heavy equipment rental	-	700	-	-	-	-	105	806	-	806	-	-	-	-	-
4	Small tool allowance	-	14	-	-	-	-	2	16	-	16	-	-	-	-	-
5	Plant energy budget	-	-	-	-	-	9	1	10	-	10	-	-	-	-	-
6	Emergency Planning Fees	-	-	-	-	-	648	65	713	713	-	-	-	-	-	-

APPENDIX D
HUMBOLDT BAY 2006 SAFSTOR
DECOMMISSIONING COST
(Thousands of 2002 dollars)

ID Number	Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
Period 5 Undistributed Costs (continued)																
7	Site Security	-	-	-	-	-	21	3	24	-	24	-	-	-	-	-
8	ISFSI O&M	-	-	-	-	-	179	54	233	233	-	-	-	-	-	-
9	ISFSI Fixed Costs	-	-	-	-	-	3,563	1,069	4,632	4,632	-	-	-	-	-	-
10	ISFSI Security	-	-	-	-	-	6,876	2,063	8,939	8,939	-	-	-	-	-	-
11	NRC ISFSI Fees	-	-	-	-	-	1,700	511	2,211	2,211	-	-	-	-	-	-
Subtotal Undistributed Costs Period 5		-	714	-	-	-	13,021	3,876	17,611	16,755	856	-	-	-	-	-
Staff Costs																
	DOC Staff Cost	-	-	-	-	-	497	75	571	-	571	-	-	-	-	-
	Utility Staff Cost	-	-	-	-	-	1,217	183	1,400	1,260	140	-	-	-	-	-
TOTAL PERIOD 5		-	1,836	-	-	141	17,091	5,077	23,945	22,094	1,850	-	-	-	14	4,303
TOTAL COST TO DECOMMISSION		2,590	30,876	2,929	1,740	47,443	166,541	48,455	300,374	297,248	3,126	81,767	1,321	423	14	334,494

TOTAL COST TO DECOMMISSION WITH	21.04%	Contingency:	$300,374,371	
TOTAL NRC LICENSE TERMINATION COST IS:	98.96%	OR:	$297,248,465	
NON-NUCLEAR DEMOLITION COST IS:	1.04%	OR:	$3,125,906	
TOTAL RADWASTE VOLUME BURIED:			83,524	Cubic Feet
TOTAL CRAFT LABOR REQUIREMENTS:			334,494	Man-hours

NOTES:

"0" indicates costs less than $500

1) This activity is performed by the decommissioning staff following plant shutdown; the costs for this are included in this period's staff cost.

2) This activity is a milestone

3) 240,775 cubic feet of demolition debris is disposed of at a controlled site

APPENDIX E

HUMBOLDT BAY 2006 SAFSTOR
CPUC COST DISALLOWANCES DECOMMISSIONING COST

APPENDIX E
HUMBODLT BAY 2006 SAFSTOR
CPUC COST DISALLOWANCES
(Thousands of 2002 dollars)

Activity	Decon	Remove	Pack	Ship	Bury	Other	Contingency	Total	Lic Term	Clean	A CF	B CF	C CF	>C CF	Craft Labor Hours
Disposal of Plant Systems															
1.1 Clean Seismic Modifications	-	13	-	-	-	-	2	15	-	15	-	-	-	-	310
1.2 Contaminated Seismic Modifications	-	60	0	0	0	25	19	105	105	-	4	-	-	-	1463
1.3 Off Gas Modifications	-	38	1	1	12	35	18	106	106	-	87	-	-	-	891
1 Totals		111	1	1	13	60	39	225	210	15	90				[illegible]
Period 4 Undistributed Costs															
1 Small tool allowance	-	87	-	-	-	-	13	100	90	10	-	-	-	-	-
2 Disposal of DAW generated	-		101	2	81	-	31	215	215	-	581	-	-	-	1579
Subtotal of Undistributed Costs		87	101	2	81		44	315	305	10	581				1579
Demolition of Remaining Site Buildings															
2.1 New Off Gas Vault	-	79	-	-	-	-	12	90	-	90	-	-	-	-	1294
2.2 Seismic Modifications	-	72	-	-	-	-	11	82	-	82	-	-	-	-	1344
2 Totals		150					23	173		173					2638
TOTAL COST TO DECOMMISSION		349	102	3	94	60	105	713	515	198	671				6881

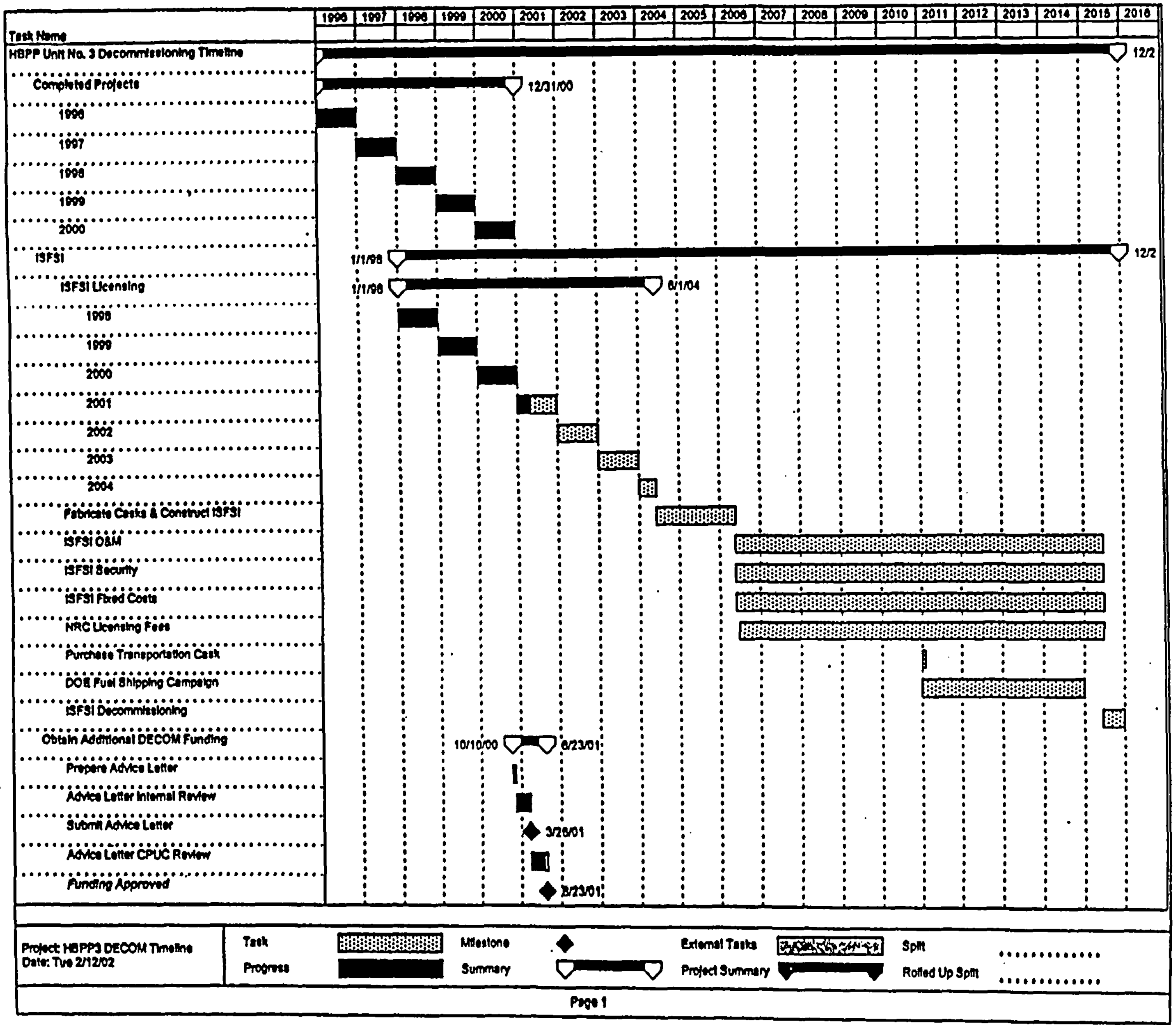
TOTAL COST TO DECOMMISSION WITH	17.32%	Contingency:	$712,869	
TOTAL NRC LICENSE TERMINATION COST IS:	72.26%	OR:	$515,105	
NON-NUCLEAR DEMOLITION COST IS:	27.74%	OR:	$197,764	
TOTAL RADWASTE VOLUME BURIED:			671	Cubic Feet
TOTAL CRAFT LABOR REQUIREMENTS:			6,881	Man-hours

"0" indicates costs less than $500

APPENDIX F

HUMBOLDT BAY 2006 SAFSTOR DECOMMISSIONING SCHEDULE

APPENDIX F
(continued)



APPENDIX F
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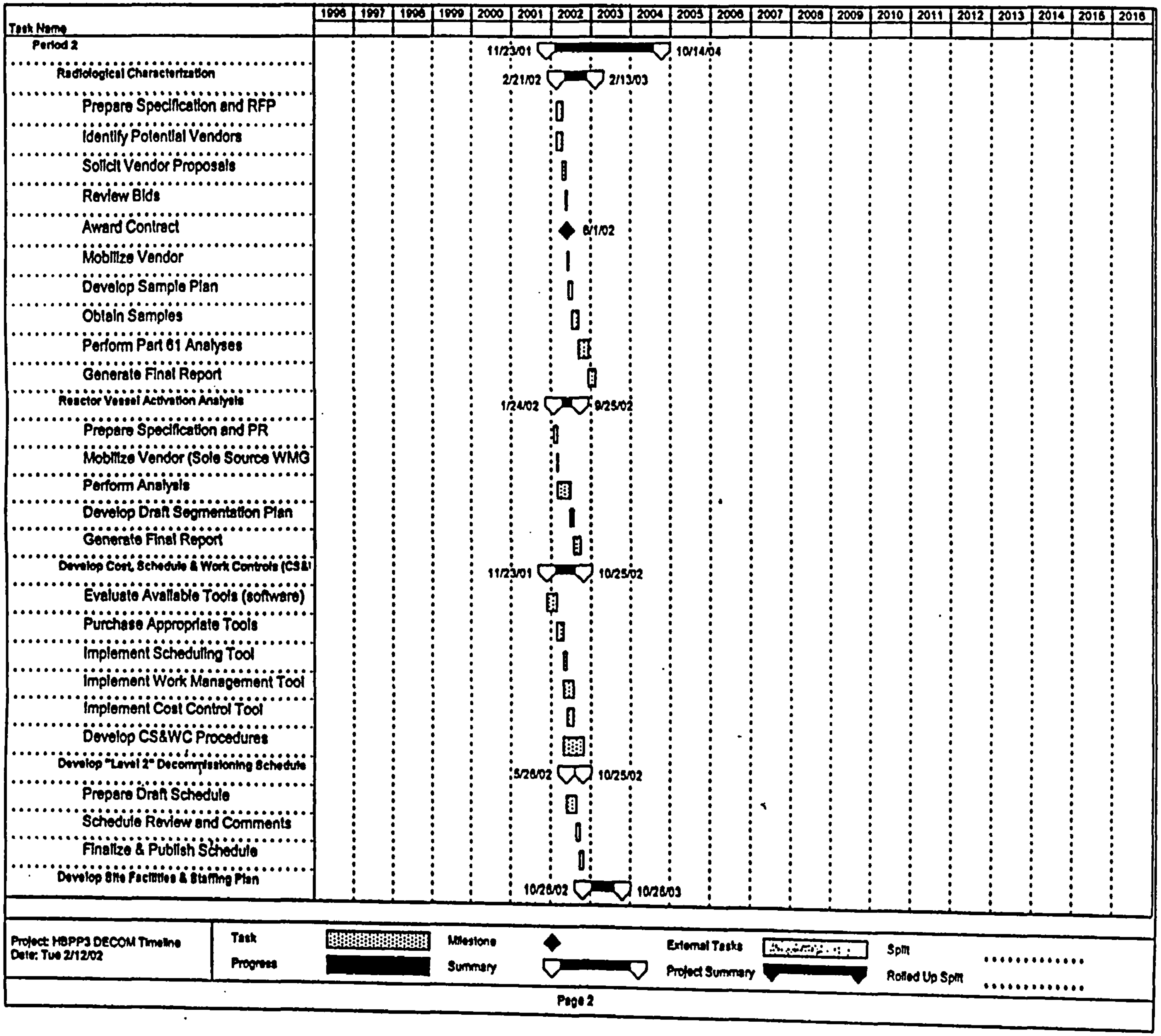

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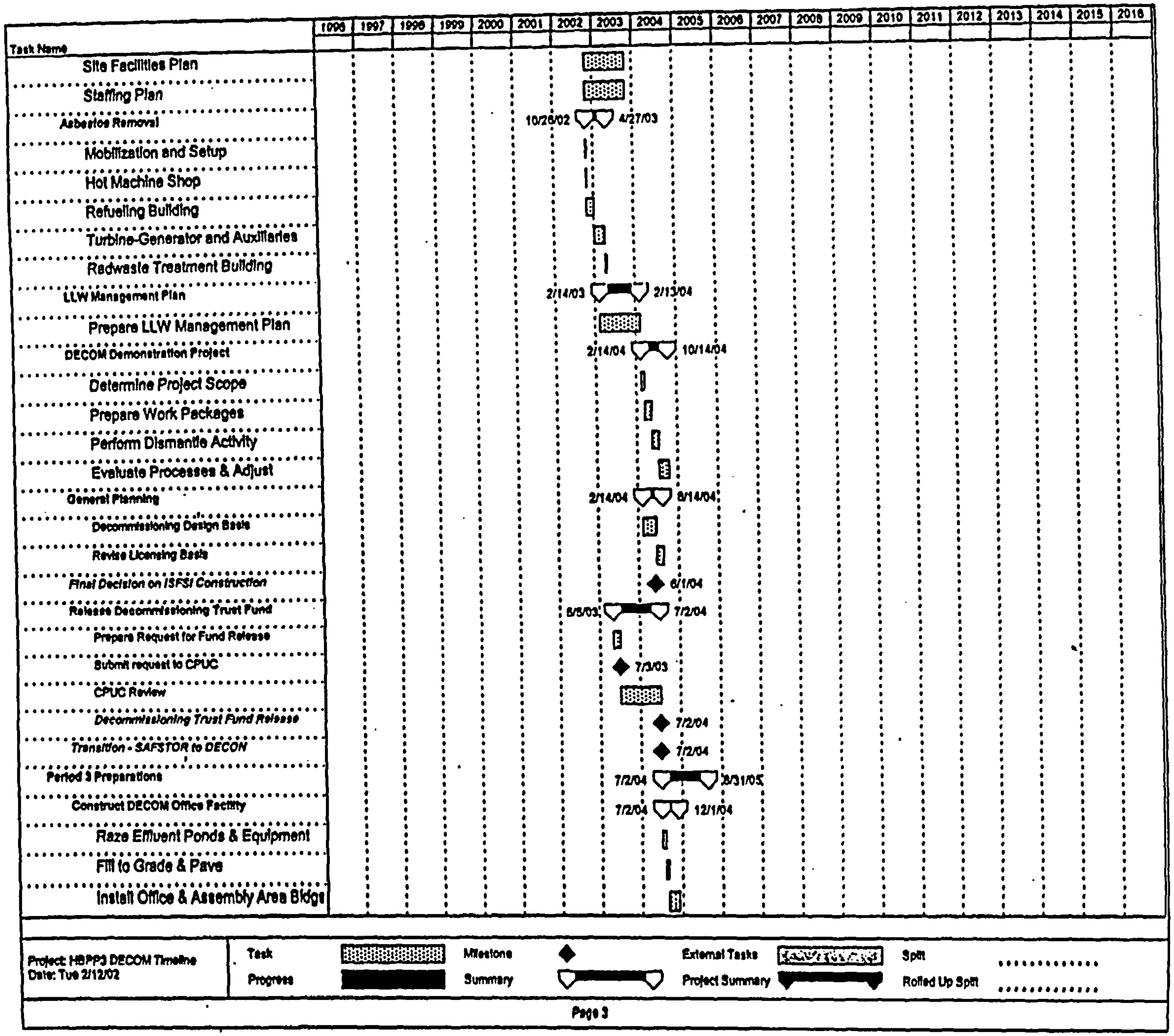

APPENDIX F
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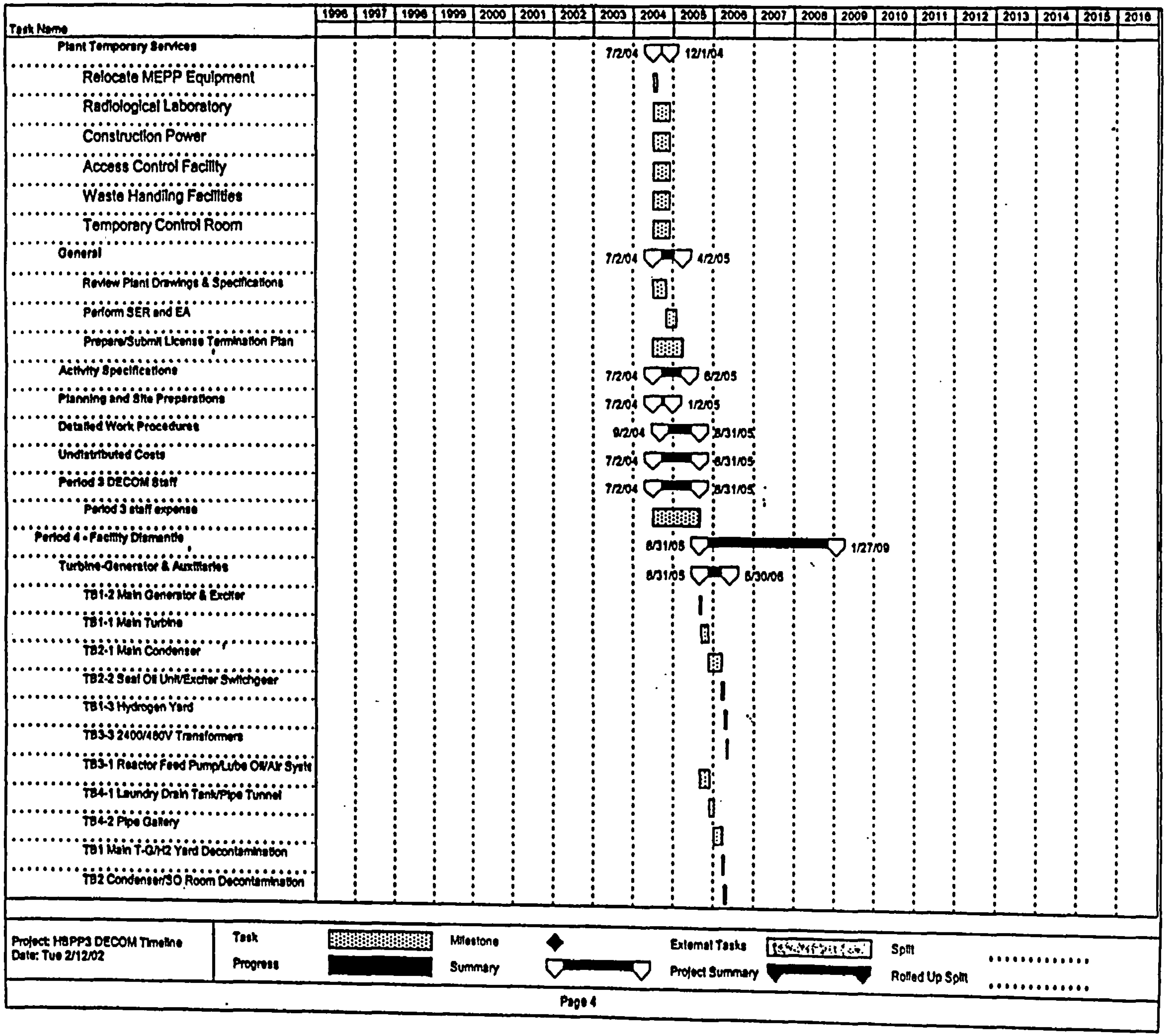

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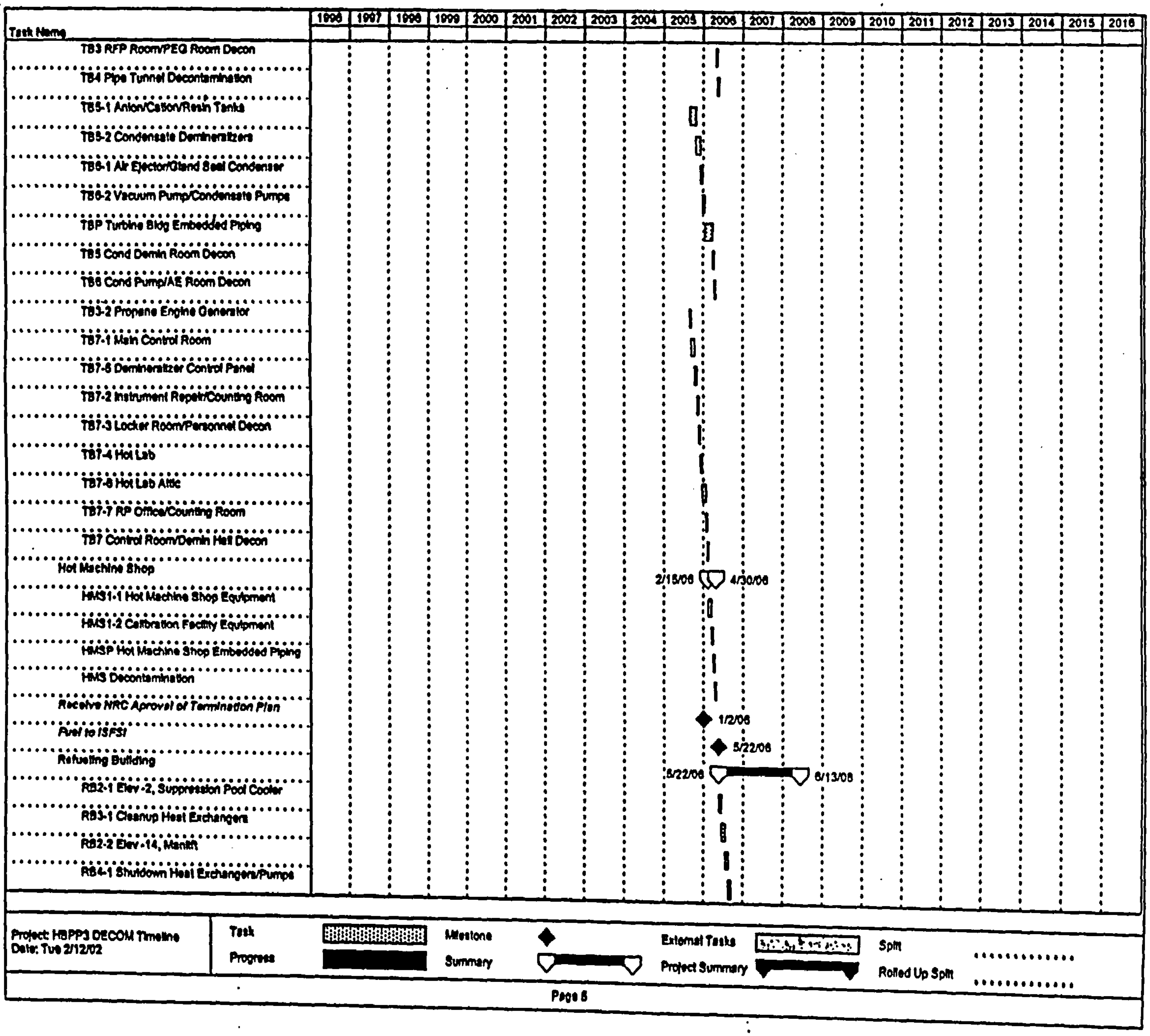

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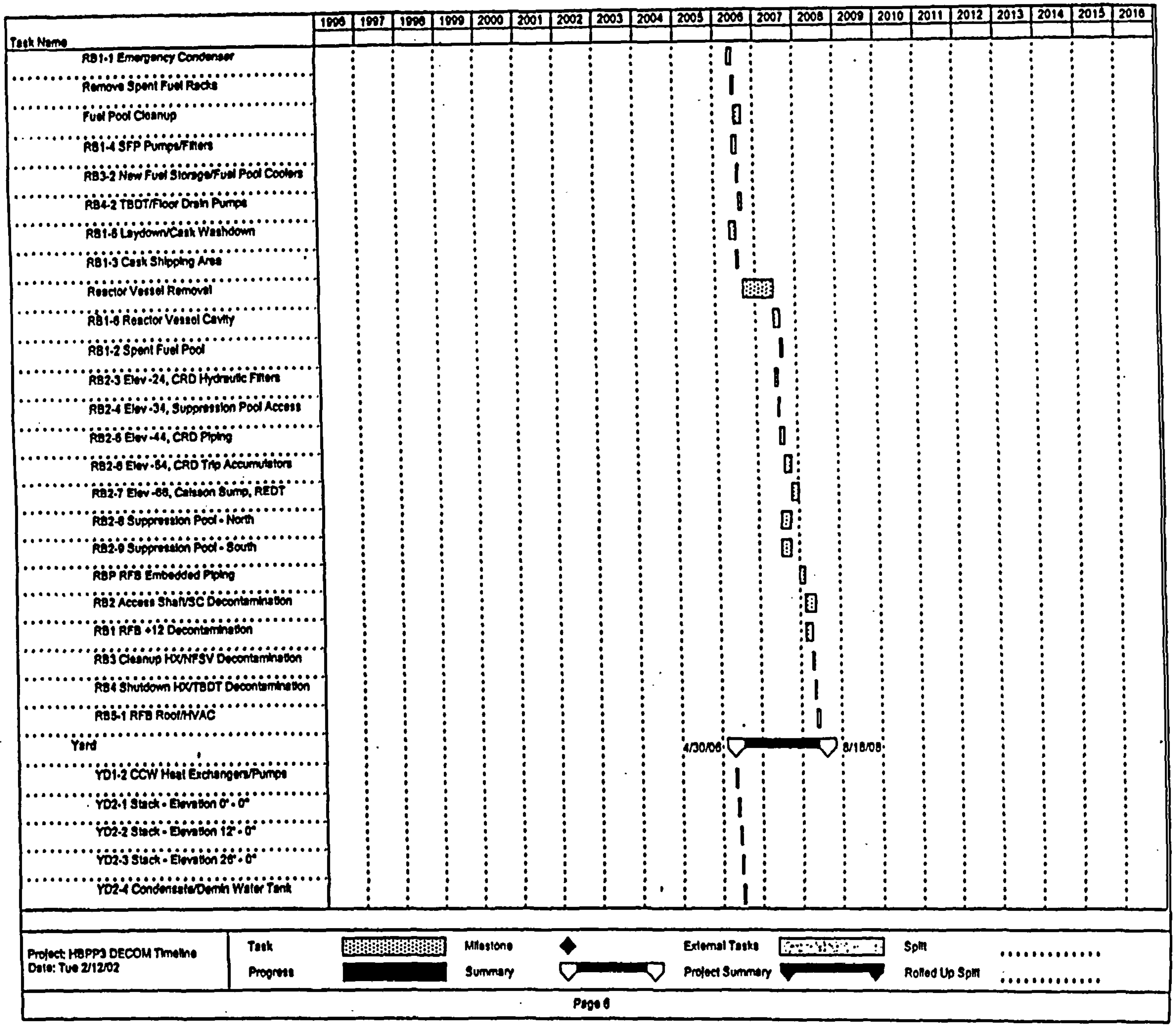

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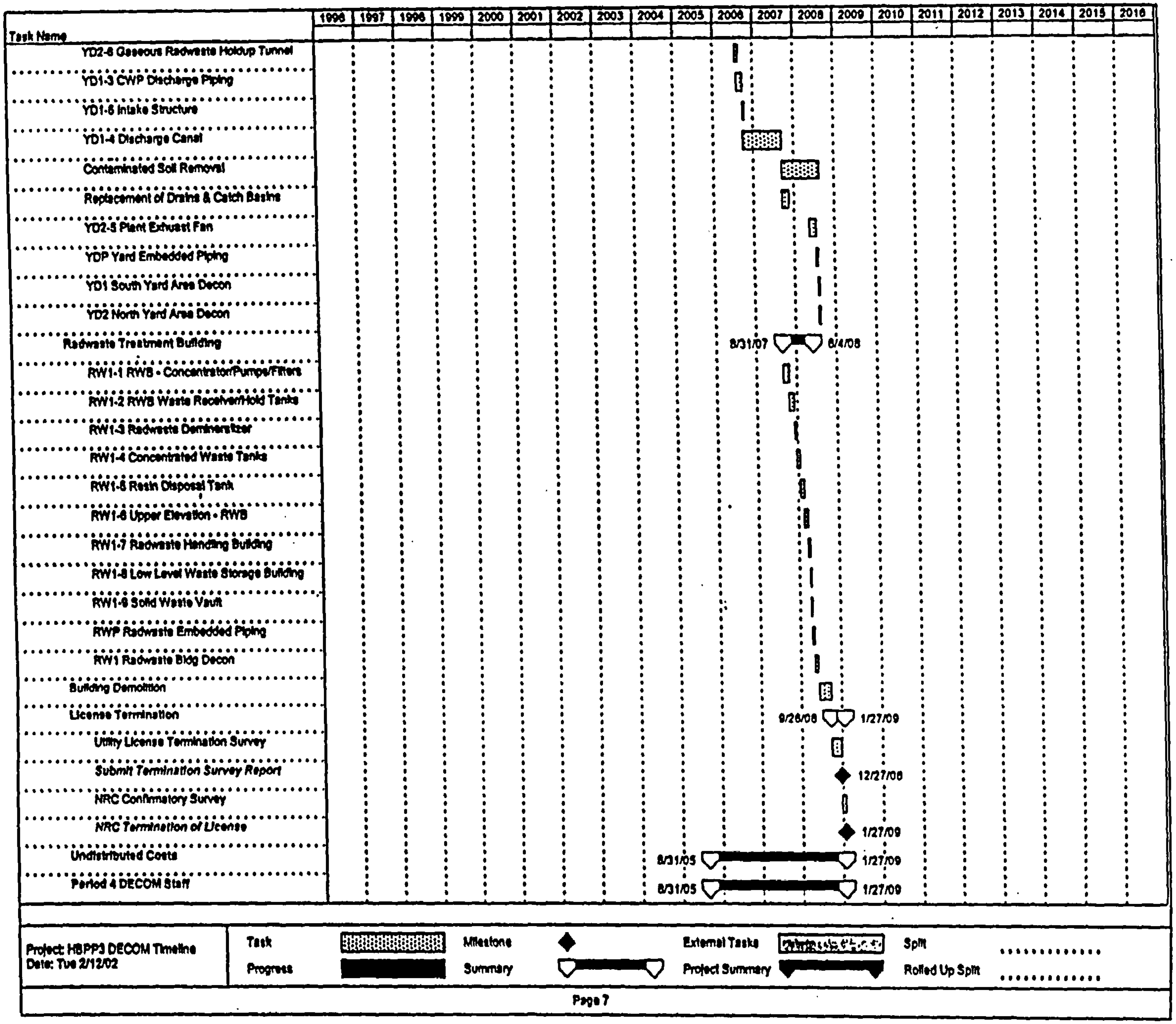

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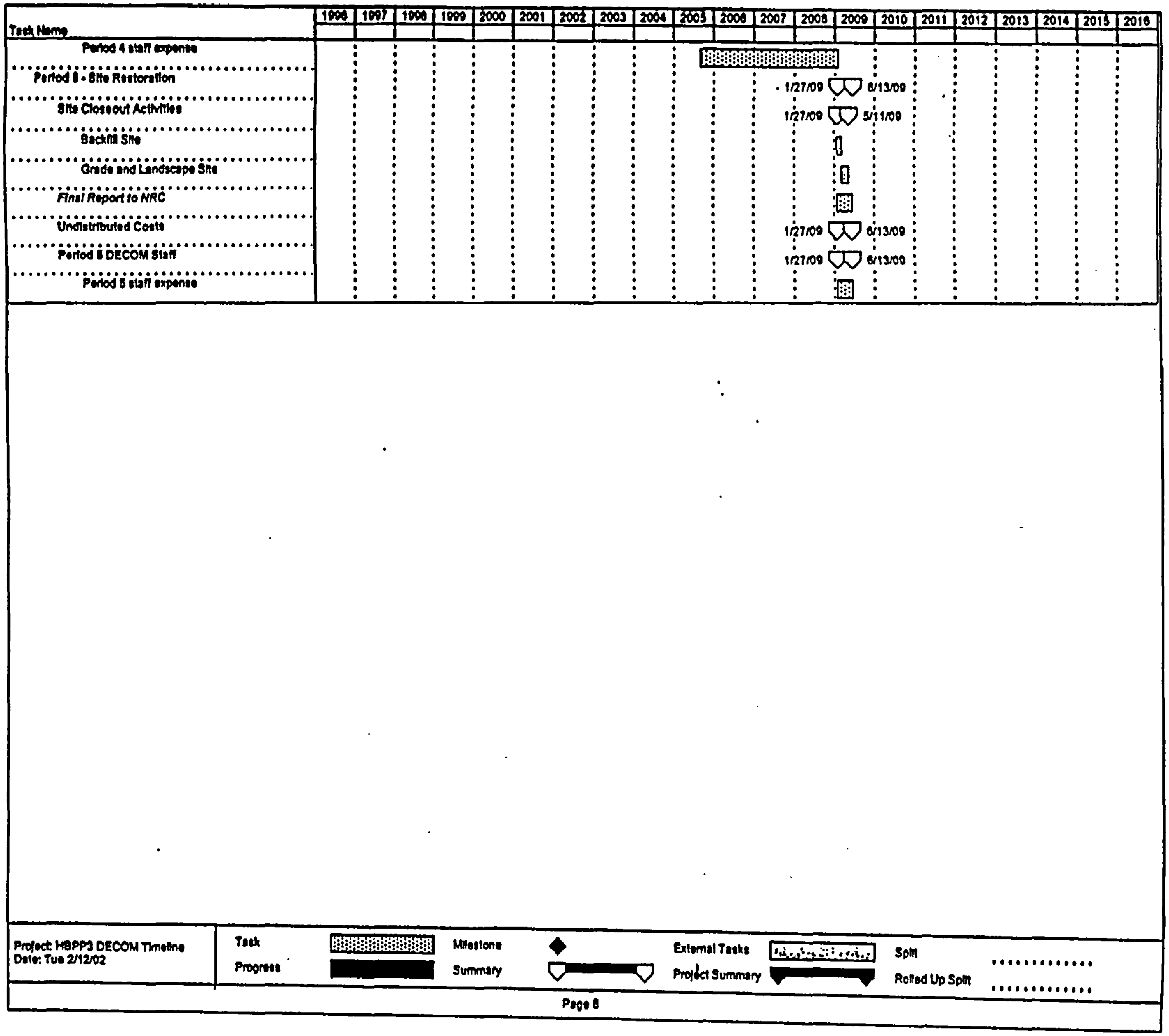

California Public Utilities Commission Decision 03-10-014

 Mailed 10/9/2003

Decision 03-10-014 October 2, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company in its 2002 Nuclear Decommissioning Cost Triennial Proceeding. (U 39 E)	Application 02-03-020 (Filed March 15, 2002)

Robert B. Mc Lennan, Attorney at Law, for Pacific Gas and Electric Company, applicant.
Gregory Heiden, Attorney at Law, for the Office of Ratepayer Advocates; Scott L. Fielder, Attorney at Law, for the Surfrider Foundation; and Bob Finkelstein, Attorney at Law; and Bill Marcus for The Utility Reform Network; interested parties.

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OPINION

I. Summary

The purpose of this nuclear decommissioning cost triennial proceeding (NDCTP) is to set the annual revenue requirements for the decommissioning trusts for nuclear power plants owned by Pacific Gas and Electric Company (PG&E).

For 2003, PG&E requests an annual revenue requirement of $24.034 million for decommissioning Diablo Canyon Power Plant Units 1 and 2 (Diablo Canyon). PG&E also requests an annual revenue requirement of $17.511 million for decommissioning Humboldt Bay Power Plant Unit 3 (Humboldt). In addition, PG&E requests $8.254 million for Humboldt SAFESTOR O&M.[1] The resulting annual revenue requirement is $49.799 million.

By this decision, we find that the trust funds for Diablo Canyon are sufficient to pay for its eventual decommissioning. In addition, we set the annual revenue requirement for Humboldt at $18.450 million. The primary reasons for the differences between the requested and adopted numbers are different adopted rates of return for the trusts, cost escalation rates, contingency factors, and low level radioactive waste (LLRW) burial costs. We also grant PG&E's request for a revenue requirement of $8.254 million for Humboldt SAFESTOR O&M. The total adopted annual revenue requirement of $26.704

[1] SAFSTOR is a decommissioning alternative in which the nuclear facility is placed and maintained in a condition that allows it to be safely stored and subsequently decontaminated. O&M stands for operations and maintenance expenses.

million is a $4.48 million decrease from the currently adopted revenue requirement of $31.2 million.

In addition to the above revenue requirement, we find that the $0.95 million expenditure for Humboldt decommissioning costs incurred above the $15.7 million authorized in Resolution E-3503 was reasonable, and authorize PG&E to recover the costs from the Humboldt decommissioning cost trusts. We also order the $3.5 million and $3.85 million Humboldt decommissioning projects authorized in Resolution E-3737 to be reviewed for reasonableness in the next NDCTP, after they have been completed.

II. Background

Application (A.) 02-03-039 is the application of Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E) for their 2002 NDCTP. Combined hearings were held for both the instant application and A.03-03-039, although the proceedings were not consolidated. The purpose of the combined hearings was to address issues common to both proceedings in a single set of hearings. In this way, a record was developed that allows the Commission to treat common issues consistently. Therefore, the testimony and exhibits of PG&E, SCE, SDG&E, and the Commission's Office of Ratepayer Advocates (ORA) regarding common issues are included in the record for both applications. The testimony and exhibits regarding utility specific issues are included only in the application to which they pertain.

SCE and SDG&E are not parties to this application. However, they participated in the development of the record. The Surfrider Foundation, and The Utility Reform Network are parties to this proceeding. However, they did not provide testimony or exhibits, cross-examine witnesses, or file briefs in this proceeding. Therefore, the term "parties," as used in the balance of this proceeding, refers to the active parties, PG&E and ORA. In addition, the term "participants" refers to PG&E, SCE, SDG&E, and ORA.

Trust fund contribution levels and the resulting revenue requirements are calculated using complex computer models. The models are first used to estimate the decommissioning costs in current dollars. The decommissioning costs are then escalated to the future years in which they will occur. The models then use the current trust fund balances, and estimated future earnings, to estimate the trust fund contributions necessary to pay the decommissioning costs when they occur. The models then determine the revenue requirement needed to provide the contributions. The disputed issues in this proceeding concern model inputs and assumptions as addressed below.

III. Overview

PG&E is requesting the following revenue requirements:

Diablo Canyon Decommissioning	$24.034 million
Humboldt Nuclear Decommissioning	$17.511 million
Humboldt SAFSTOR O&M	$ 8.254[2] million
Total Request	$49.799 million

2 In its application, PG&E requested $7.343 million. It revised the request to include $669,000 in additional direct post 9/11 security costs and $200,000 for Department of Energy Decontamination and Decommissioning fees for federal facilities used to produce nuclear fuel, plus the addition of franchise fees and uncollectibles, and administrative and general costs.

IV. Utility-Specific Issues

A. Diablo Canyon Decommissioning Cost Estimate

PG&E's Diablo Canyon decommissioning cost estimate assumes that Diablo Canyon Unit 1 will be shut down in 2021, and Unit 2 shut down in 2025. PG&E estimated decommissioning costs using two methodologies: DECON, which is where radioactive contaminants are removed or decontaminated shortly after cessation of operations; and SAFSTOR. PG&E estimates that the DECON alternative will cost $1.377 billion (in 2002 dollars) over a 20-year period starting in 2021, and that SAFSTOR will cost $1.363 billion (in 2002 dollars) over a 41-year period. In this proceeding, PG&E selected the DECON alternative, which results in removal of the Diablo Canyon units more quickly.

ORA does not oppose the decommissioning cost study upon which PG&E's estimate is based. However, ORA does oppose PG&E's contingency factor, rates of return, escalation rates, and low level radioactive waste (LLRW) burial cost estimates. These issues are addressed later in this decision under Common Issues.

ORA points out that PG&E informed the Nuclear Regulatory Commission (NRC) that it is fully funded regarding the NRC's minimum requirements for decommissioning Diablo Canyon, and needed no further funding at this time. While PG&E admits that it made the statement, it explains that the NRC's minimum requirements include only the costs associated with radiological decommissioning. In addition, the calculation of the decommissioning costs is required to be based on a 1986 cost estimate provided by the NRC. Thus while PG&E says that Diablo Canyon decommissioning is fully funded as far as the NRC's requirements are concerned, PG&E says its estimate in this proceeding is based on a site-specific study that uses current estimated costs, and includes non-radiological decommissioning and site restoration. As a result, the scope of work and, therefore, the resulting decommissioning cost, is significantly greater than required by the NRC.

The NRC's requirements are far more limited than those addressed herein. We find that PG&E's statement to the NRC does not contradict its statements in this proceeding, and has no bearing on this proceeding.

B. Humboldt Decommissioning Costs and O&M Expenses

Humboldt is currently in SAFSTOR mode following its shutdown in 1976. PG&E studied two alternatives: decommissioning starting in 2015, at a cost of $362 million in 2002 dollars; and early decommissioning starting in 2006 at an approximate cost of $300 million in 2002 dollars. PG&E recommends the early decommissioning alternative, which removes non-fuel related radioactive materials, while waiting for the federal Department of Energy to be able to take delivery of spent fuel. Since early decommissioning is less costly, we will adopt PG&E's recommendation.

ORA does not oppose the decommissioning cost study upon which PG&E's estimate is based. However, ORA does oppose PG&E's contingency factor, escalation rates, rates of return, and LLRW burial cost estimates. These issues are addressed later in this decision under Common Issues.

PG&E requests authority to recover the direct costs of its SAFESTOR O&M expenses for Humboldt for 2003 that it estimates to be $8.254 million. It also requests authority to adjust the administrative, general, tax, and allocated common plant amounts in this calculation in its 2003 general rate case. In addition, PG&E requests attrition for its SAFESTOR O&M expenses in the amounts of $218,000 for 2004, and $ 230,000 for 2005. ORA does not oppose these requests. Since the requests are unopposed, we will grant them.

C. Early and Partial Decommissioning of Humboldt

PG&E has already commenced early decommissioning activities at Humboldt. In Resolution E-3503, adopted December 3, 1997, the Commission authorized PG&E to spend $15.7 million on three decommissioning activities: mitigation of caisson in-leakage; removal and replacement of the ventilation stack; and a site radiological survey to support the decommissioning cost study. The Commission also found it reasonable to use the decommissioning trust funds to finance the three projects.

In Advice Letter 2095-E, submitted on March 28, 2001, PG&E requested authority to draw not more than $8.3 million from the Humboldt Bay decommissioning trust funds to finance three additional decommissioning expense categories: $0.95 million for decommissioning costs incurred above the $15.7 million authorized in Resolution E-3503; $3.5 million for additional design and licensing expenditures above the $7 million authorized in Decision (D.) 00-02-046; and $3.85 million for preparatory activities during 2001 through 2003 in anticipation of early transition from SAFESTOR to decontaminated status in 2004. In Resolution E-3737, adopted October 10, 2001, the Commission found it reasonable to use the decommissioning trust funds to finance the proposed projects. The request was approved in part subject to review of the requested expenditures in this proceeding, and subject to refund of any imprudent and unreasonable expenditures. The $3.5 million and $3.85 million requests were approved subject to the above provisions. The $0.95 million request was denied, without prejudice, until reviewed for prudence and reasonableness in this proceeding.

The three projects addressed in Resolution E-3503 were completed. The $0.95 million increase was primarily due to higher-than-expected levels of radiation in the suppression chamber, which required an expansion of the scope of the project, and increased costs for removal of the ventilation stack. ORA does not oppose PG&E's request to use the nuclear decommissioning trust funds to pay the $0.95 million in costs.

PG&E and ORA agree that the $3.5 million and $3.85 million activities authorized in Resolution E-3737 have not been completed. They also agree that the unfinished projects should be reviewed for reasonableness in the next NDCTP, after they have been completed.

Discussion

As recommended by the PG&E and ORA, we find that the $0.95 million expenditure was reasonable, and PG&E should be authorized to use the trust funds to pay for the expenditure. In addition, we find that the unfinished projects should be reviewed for reasonableness in the next NDCTP, after they have been completed.

D. Equity Turnover Assumption

In order to determine the net returns the trust funds will earn each year, it is necessary to make an assumption as to the amount of taxable capital gains that will be realized on equities during the year. This, in turn, necessitates an assumption as to the amount of equities sold each year.

PG&E assumed that 100% of the equities will be sold each year. It says that this assumption was adopted by the Commission in D.00-02-046. PG&E asserts that one cannot accurately predict when a portfolio manager will choose to sell a particular stock and take a capital gain or loss. PG&E's conservative approach is to assume that all of the trusts' equities are sold each year. This results in all of the annual gains or losses being taxed each year. Additionally, taxes are paid annually on all income and interest to the trust.

ORA points out that PG&E's forecast assumes that all trust fund earnings are taxed each year although, in reality, capital gains are only taxed when securities are sold. It argues that PG&E's assumptions ignore the benefits of deferring taxes by holding securities for a longer term. Therefore, PG&E's methodology overestimates actual taxes, causing an underestimation of future fund balances. ORA claims that PG&E's estimates do not accurately reflect how its funds are actually managed and taxed. For example, although PG&E fully taxes the trusts each year in its estimates, there will be no significant withdrawals from the decommissioning funds until 2021 and 2023, which means that, in reality, there will not be any significant capital gains until then. ORA believes that PG&E's approach does not accurately describe how the funds will actually be managed.

Discussion

PG&E's assumption of a 100% annual equity turnover rate is overly conservative. For 1999 through 2002, PG&E's annual equity turnover rate ranged from 18% to 27% for qualified trusts, with an average of 24%.[3] For 2000 through 2002, its annual equity turnover rate ranged from 18% to 49% for non-qualified

[3] There are two types of trusts. Qualified trusts hold decommissioning funds that result from contributions that qualify for an income tax deduction under U.S. Internal Revenue Code Section 468A. Nonqualified trusts hold decommissioning funds that result from other contributions.

trusts, with an average of 29%. PG&E has given us no reason to believe that future equity turnover rates will be substantially different from the recorded turnover rates. Therefore, we will assume a 24% annual turnover rate for equities in the qualified trusts, and 29% for equities in the non-qualified trusts. For any year in which a higher amount of equities will need to be sold to pay for decommissioning costs, the higher amount should be used.

V. Common Issues

A. Rate of Return

For estimating the earnings of the nuclear decommissioning trusts, PG&E estimates an 11.0% pre-tax return on equities and a 7.0% pre-tax return on its fixed income assets. SCE estimates a pre-tax return on equities of between 7.42% and 10.11%, and a pre-tax return on fixed income assets of between 4.21% and 6.03%. SDG&E estimates a pre-tax return on equities of 7.42%, and a pre-tax return on fixed income assets of 6.03%. ORA recommends a 12.5% pre-tax return on equities and a 7.4% pre-tax return on fixed income assets.

PG&E's equity return forecast is based on the annualized rate of return for the U.S. equity market over rolling 10-year periods covering 80 years, from 1920 through 2001. PG&E believes that forecasts of long-term market returns are traditionally based on historic market experience over very long time periods, and it is preferable to include more data points where available to decrease the variance in the results. In PG&E's last general rate case (D.00-02-046), the Commission adopted an 11.0% pre-tax return on equities. PG&E believes an 11.0% pre-tax return on equities remains a reasonable and conservative forecast. In D.00-02-046, the Commission also adopted a 7.0% pre-tax return on the fixed income portion of PG&E's trusts. PG&E recommends the same value in this proceeding.

SCE used two sets of return assumptions to establish a range of contributions to its decommissioning trust funds for San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2&3) and Palo Verde Nuclear Generating Station Units 1, 2, and 3 (Palo Verde). The first set of assumptions relies on DRI-WEFA (DRI)[4] projections for: (1) the Standard & Poor's (S&P) 500 Stock Price Index, and (2) the dividend yield for the S&P 500 Stock Index, to calculate future equity returns. SCE maintains that when compared to estimates derived from historical data, DRI's Treasury bond yield projections are too high relative to their inflation projection, and DRI's estimate of future equity returns is too low. Therefore, it constructed an alternative set of return assumptions that adjust Treasury bond yield projections and future equity returns to reflect historical relationships. SCE believes that its two sets of return assumptions bound expected returns for the decommissioning trust funds.

SDG&E argues that it does not make sense to adopt identical rate of return assumptions for itself, SCE and PG&E because each company has its own separate and independent decommissioning trusts with portfolios of hundreds of different domestic and international stocks. Moreover, each company has different investment committees with different risk tolerances. As a result of these differences, the three utilities may choose different portfolio asset allocations, investment strategies, and investment advisors, all of which will impact the realized investment rates of return.

SDG&E used DRI projections as the basis for computing expected equity and fixed-income asset returns. SDG&E maintains that DRI forecasts

[4] DRI is a company that provides economic forecasts.

should be consistently used in determining funding requirements. It believes that using DRI forecasts consistently over time provides the Commission with a consistent gauge to assess performance, and provides fewer opportunities for gaming that could occur if methodologies are changed every three years.

Specifically, DRI projects that the average annual pre-tax return for the S&P 500 and 10-year Treasury bonds will average 7.42% and 6.03%, respectively, from 2002 through 2026, which covers the period that contributions will be made (through 2013) to the decommissioning trusts.[5] SDG&E says the DRI forecast is also consistent with equity projections from a variety of investment professionals.

ORA recommends a 12.5% pre-tax return on equities, and a 7.4% pre-tax return for fixed income investments. ORA's 12.5% pre-tax return on equities is derived from the 48-year (1954-2001) average annual return for the S&P 500 of 12.77%. ORA contends that evaluating historic performance beginning in 1954, after the Federal Reserve removed its cap on government debt rates, creates a more reliable historic record than using data beginning before the Great Depression, as PG&E has done. Furthermore, using 1954 as a starting date allows analysis of 10-year Treasury bond data.

ORA says the Commission should not adopt PG&E's rate of return assumptions when the historic results have been much higher. ORA points out that PG&E's estimates are lower than readily available investment options such as tax-free municipal bonds. ORA believes its 7.4% pre-tax return for fixed

[5] SDG&E expects to collect decommissioning contributions only through 2013 (through the end of operations), although it will continue to invest in equities until commencement of decommissioning.

income investments is comparable to the DRI forecast, current municipal bond rates, and actual performance of the trust funds.

While ORA does not oppose SCE's methods, it does oppose SDG&E's methods. SDG&E relied exclusively on DRI long-term forecasts. In contrast, ORA says that SCE's rate of return estimate uses DRI and its own estimates to forecast its decommissioning fund performance. ORA says SCE's approach is preferable because it incorporates consideration of the historical premium for equity risk that it believes has virtually disappeared in the DRI projections.

ORA also says that SDG&E did not back-test the DRI projections for accuracy. DRI's short-term equity performance forecast from the 1998 NDCTP did not forecast the current state of the equities market. ORA believes that using the DRI projections alone, without any adjustments for historical risk premium, is not a good methodology.

Discussion

As pointed out by SDG&E, each utility has its own separate and independent decommissioning trust portfolios. In addition, each utility has different investment committees with different risk tolerances. As a result of these differences, SCE, SDG&E, and PG&E's realized investment rates of return will be different. However, in this proceeding, none of the participants has indicated specifically how these factors are incorporated into its estimates. In addition, the three utilities' trusts will have access to the same markets. As a result, their trusts will have the same investment opportunities. Therefore, we will adopt a uniform set of rate of return projections for all three utilities.

For equity returns, there is merit in using long-term historical data as used by PG&E and ORA. However, their presentations demonstrate that selection of which data to use can give quite different results. In contrast to the historical data, the DRI forecasts, which SDG&E and SCE use in different ways, yield much lower returns. No participant has demonstrated that its estimate is substantially better than the rest. The midpoint of the range of values recommended by the participants is below the 11.0% pre tax return on equities we adopted for PG&E in D.00-02-046.[6] This leads us to believe that some reduction is appropriate. Therefore, we will adopt a 10.5% pre-tax return on equities, which is slightly above the midpoint of the range of values estimated by the participants.

Regarding fixed assets, no participant has demonstrated that its estimate is substantially better than the rest. Since the midpoint of the range of values recommended by the participants is below the 7.0% pre tax return on fixed assets we adopted for PG&E in D.00-02-046, some reduction is appropriate. Therefore, we will adopt a 6.0% pre-tax return on fixed assets, which is slightly above the midpoint of the range of values estimated by the participants.

B. Escalation Rate

The escalation rate is used to bring the current estimate of decommissioning costs to the future years in which the costs will be incurred.

PG&E calculated the simple average of the escalation rates for labor, LLRW burial costs, contract labor, materials, and other costs to arrive at an annual escalation rate. It then added a 20% contingency factor to arrive at its recommended overall escalation rate.

PG&E's escalation rates, except for LLRW burial costs, are based on DRI forecasts. The DRI forecasts do not extend beyond 2023. Therefore, PG&E

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[6] The current trust fund contribution levels for SCE and SDG&E were adopted in D.99-06-007. That decision approved a settlement and, therefore, is not a precedent.

used a DRI forecast to calculate escalation rates until 2023, and used the 2023 rate for subsequent years. It represents that its labor, materials, contract labor and other escalation rates are comparable to the most recent DRI forecasts.

PG&E believes that using a weighted average rate simply adds false precision to a highly speculative estimate. PG&E says that its methodology is the same as was used to calculate the overall escalation rate used by PG&E, and adopted by the Commission in D.00-02-046.

PG&E added a 20% contingency factor to come up with its overall escalation rate.[7] PG&E states that the contingency factor ensures against future ratepayer liabilities by recognizing uncertainties with regard to changes in the economy, and protects against uncertainties in how much decommissioning costs may increase in the future.

PG&E recommends a 7.5% LLRW burial cost escalation rate for use in this proceeding as it was in D.00-02-046. PG&E says it is uncertain where the LLRW will be buried, and how much it is going to cost. PG&E believes that since the uncertainty is even greater now, with the Ward Valley disposal site stalled, and other sites about to stop taking California LLRW, a 7.5% LLRW burial cost escalation rate is a conservative and reasonable assumption.

SCE and SDG&E (the utilities) calculated separate escalation rates for: (1) labor, (2) the combined category of material, equipment, and other, and (3) LLRW burial costs. They based the separate escalation rates for labor, and the combined category of material, equipment, and other upon DRI projections. The

[7] In D.00-02-046, the Commission adopted a 25% contingency factor.

escalation rate for the combined category of material, equipment, and other was based on a weighted average of the escalation rates for each component.

The utilities used Nuclear Regulatory Commission (NRC) published data to estimate an escalation rate for LLRW burial costs. The NRC data shows rapidly increasing burial costs followed by large, discrete jumps. The utilities utilized two similar statistical models to produce ten estimates ranging from 6.8% to 19.9%. They then chose a 10% LLRW burial cost escalation rate because of the possibility of additional large jumps in LLRW burial costs.

The utilities did not include a separate contingency factor in their calculation of escalation rates.

ORA argues that an unweighted average escalation rate makes no statistical sense, and overestimates actual escalation. ORA maintains that PG&E's unweighted calculation gives a 20% weighting to each of the five categories. However, the equipment and materials category accounts for 29%, and the "other" category accounts for 6% of actual expenditures, rather than the 20% used by PG&E for these two categories. ORA contends that this proves the inaccuracy of using an unweighted average. As a result, ORA recommends that a weighted average, based on expenditures, be used.

ORA also says that PG&E's use of the 2023 value for years after 2023, when using DRI forecasts in calculating an average escalation rate, gives undue weight to the 2023 value. It points out that, while the escalation rates in the earlier years have some relation to historic costs, the years after 2023 are not based on any independent forecast.

ORA contends that PG&E relied on a DRI forecast from 2001 in generating the labor escalation rate, and that a more recent DRI forecast yields significantly lower numbers. Therefore, ORA recommends that the Commission adopt the most recent DRI data.

ORA also says that PG&E's request for an additional 20% contingency factor is redundant since an overall contingency factor is already built into its decommissioning cost estimate.

ORA recommends a 5% escalation rate for LLRW burial costs. This is because burial costs increased only 2.4% from 1996 to the present, and only 4.3% from 2000 to 2001. ORA says that PG&E's only rationale for using a 7.5% burial cost escalation rate is that the Commission has previously adopted it.

ORA also opposes the utilities' proposed 10% LLRW burial cost escalation rate. It says the utilities relied entirely on NRC disposal cost indexes from 1986 to 2000, but did not attempt to independently verify the data. It believes that a reasonable cost escalation projection should consider additional factors to help explain a data set, and should look beyond the numbers to determine causes for their variation, as well as possible future developments. ORA says the utilities performed no such evaluation, and did not inquire as to why certain years were missing from the NRC data, or why the costs jumped significantly in certain years.

ORA maintains that the utilities' choice of data is not representative of future costs. ORA says the data used by the utilities, from three disposal sites for the period 1986-2000, reflects non-competitive disposal pricing. It also says that more recent data under more competitive conditions for Barnwell in South Carolina, and Envirocare in Utah, including contracted San Onofre Nuclear Generating Station Unit 1 (SONGS 1) LLRW burial costs, were not considered in the utilities' estimate. ORA believes the utilities have projected the most expensive possible future scenario without consideration of the prospect of a more competitive market for burial of LLRW.

Discussion

While we agree with PG&E that we are dealing with a highly speculative estimate, that is no reason to deliberately introduce an error into the calculation. ORA has demonstrated that the actual expenditures do not support the equal weighting that results from a simple average. In addition, the utilities used a weighted average. Therefore, except for LLRW burial costs, we will require the use of a weighted average.

The participants agree that a DRI forecast should be used to forecast escalation rates, except for LLRW burial costs. The disagreement appears to be over which forecast to use. Here again, although forecasts of the future are speculative by nature, it makes sense to use the most recent available forecasts. Therefore, we will use the DRI forecasts used by ORA, which are the most recent DRI forecasts in the record.

We note that the DRI forecasts run only through 2023. When determining an average escalation rate for a forecast period, PG&E uses the 2023 rate for subsequent unforecasted years. However, as pointed out by ORA, this approach gives additional weight to the last forecasted year. There is no reason that the forecast for 2023 is any better than the forecast for other years. Therefore, the average rate for the forecast period shall be used for the subsequent unforecasted years. This means that the rate for 2024, and each year thereafter, would be the average of the rates for 2002-2023.

We adopt contingency factors for cost estimates when the work to be done may change substantially over time due to such things as changing NRC requirements. This is the case with the decommissioning cost estimate.

However, the escalation rate is an estimate of the rate of change in the cost of specified work. The Commission routinely adopts forecasts of cost increases, in general rate cases for example, without applying contingency factors. Since the risk of substantial changes in the work to be done and the requirements that must be met to do the work is covered by the contingency factor applied to the decommissioning cost estimate, there is no reason to apply a separate contingency factor to the calculation of the escalation rate. We also note that the utilities are not requesting one. Therefore, we will not adopt a separate contingency factor for escalation rates.

Regarding the LLRW burial cost escalation rate, the utilities estimate a 10% rate based on economic modeling of NRC data, PG&E proposes a 7.5% escalation rate based on our previous adoption of it, and ORA proposes a 5% escalation rate based on burial cost increases from 1996 to the present. Since the NRC data shows significant jumps and has no data for some years, we believe that it demonstrates the uncertainty of the costs, but does not provide a good basis for estimation. Therefore, we will not adopt the utilities' 10% escalation rate. Likewise, ORA has not demonstrated that the recorded burial costs increases from 1996 to the present provide a better basis for estimation than the NRC data. Therefore, we will not adopt ORA's 5% escalation rate. As pointed out by PG&E, it is uncertain where the wastes will be buried, and at what cost. Burial costs are no less certain now than they were when the Commission adopted a 7.5% escalation rate for PG&E in D.00-02-046. Therefore, since no participant has demonstrated that its estimate is more accurate than the other estimates, it is reasonable to continue using the previously approved rate. This rate also happens to be the midpoint of the rates recommended by the participants.

C. LLRW Burial Costs

LLRW burial costs are the costs of burying the LLRW generated by the decommissioning of a nuclear power plant. PG&E estimates LLRW burial costs of $404 per cubic foot.[8]

PG&E points out that, in D.00-02-046, the Commission adopted LLRW burial costs at the Ward Valley site of $509 per cubic foot in 1997 dollars. Because there is no indication that Ward Valley will ever be available during the times it will be needed, PG&E based its estimate on the costs of the only facility in America to which it can send more-contaminated LLRW, at Barnwell, South Carolina. Even though Barnwell is going to stop accepting wastes from non-Atlantic Compact generators such as PG&E, SCE, and SDG&E, PG&E believes Barnwell's costs are appropriate because they include all of the costs a future disposal facility (such as Ward Valley is intended to be) would likely bill a generator. Given the complete uncertainty over where these wastes will eventually go, and how much it will cost once that place is identified and operational, PG&E believes its $404 per cubic foot estimate is optimistic.

The utilities' burial cost estimate is $72.60 per cubic foot for SONGS 2&3. This estimate is based on the assumed availability of a licensed

[8] In PG&E's application and exhibits, it used LLRW burial costs of $404 per cubic foot for Diablo Canyon. For Humboldt 2015 decommissioning, it used $450 per cubic foot. For Humboldt early decommissioning, it used $140 per cubic foot for Class A LLRW and $450 per cubic foot for the more hazardous classes of LLRW. This yields an average LLRW burial cost of $147 per cubic foot for Humboldt early decommissioning. In its briefs, PG&E presented its recommendation as $404 per cubic foot without distinguishing between Diablo Canyon and Humboldt. Therefore, we address only PG&E's $404 per cubic foot recommendation herein.

disposal facility with rates comparable to the Envirocare facility, and located within 1,500 miles of the SONGS site.

SCE's LLRW burial cost estimate for Palo Verde is $87 per cubic foot. SCE says its estimate is consistent with APS'[9] assumptions about the burial sites that APS will use for Palo Verde LLRW.

ORA recommends that the Commission adopt the utilities' current LLRW burial cost estimate of $72.60 per cubic foot. ORA claims that PG&E derives its $404 estimate from recent cost increases at Barnwell and other facilities. ORA believes that PG&E's methodology is faulty because it ignores the likely availability of alternative facilities. ORA argues that the utilities' $72.60 per cubic foot estimate reflects their current burial cost for all classes of LLRW. ORA does not oppose the utilities' estimated LLRW burial costs for Palo Verde.

<u>Discussion</u>

In D.00-02-046, we adopted burial costs of $509 per cubic foot (in 1997 dollars). In this proceeding, the participants have recommended costs ranging from $76.20 to $404 per cubic foot. Therefore, it appears that the participants agree that the costs should be lower. However, they disagree on how much lower they should be.

Only PG&E and SCE actually prepared LLRW burial cost estimates. SDG&E and ORA recommend use of SCE's estimate. In addition, we have no reason to believe that there will be sufficient alternative burial sites available to lower costs due to competition, as recommended by ORA. Therefore, we are left with PG&E and SCE's estimates.

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[9] The Arizona Public Service Company (APS) is the operating agent for Palo Verde.

Although both PG&E and SCE's estimates are based on actual costs, neither estimate has been demonstrated to be substantially better than the other. This circumstance argues for using a cost of $240 per cubic foot, the midpoint of the range of the proposed values. However, since SCE has done a more comprehensive analysis of decommissioning costs, especially for SONGS 2&3, we will give slightly more weight to its estimates. As a result, we will adopt a LLRW burial cost of $200 per cubic foot. This amount is a bit more than twice SCE's estimates, slightly less than half of PG&E's $406 estimate for Diablo Canyon, more than PG&E's original estimate for Humboldt early decommissioning, and substantially less than the cost adopted in D.00-02-046.

D. Contingency Factors

The contingency factor is used to increase the estimated decommissioning costs to allow for uncertainties in the required decommissioning work and, therefore, the costs. PG&E recommends an overall contingency factor of 40% for Diablo Canyon. It also proposes an overall contingency factor of 40% for Humboldt for 2015 decommissioning, and 30% for early decommissioning. In contrast, ORA recommends that the Commission adopt the engineering contingency factors estimated for PG&E by TLG Services, Inc. (TLG) for Diablo Canyon and Humboldt, as the overall contingency factors.

The decommissioning cost studies, performed by TLG for PG&E, identified engineering contingency factors of 18.83% for Diablo Canyon Unit 1, 17.95% for Diablo Canyon Unit 2, and 18.54% for early decommissioning, and 21% for 2015 decommissioning of Humboldt. PG&E proposes an overall contingency factor of 40% for Diablo Canyon to take into account the engineering contingencies addressed by TLG, as well as other non-engineering contingencies such as costs associated with delays in approval of decommissioning plans, changes in the project work scope, regulatory changes and policy decisions at the state or federal level which change the scope, timeframe or level of work required for decommissioning.[10] Similarly, it also proposes an overall contingency factor of 40% for Humboldt for 2015 decommissioning, and 30% for early decommissioning.

PG&E notes that for Palo Verde, a plant more like Diablo Canyon and whose decommissioning cost study was prepared by the same consultant that prepared PG&E's decommissioning cost studies, SCE is recommending a contingency factor of 40%. PG&E argues that SCE was able to reduce its contingency factor to 21% for SONGS 2&3 by making specific new estimates of costs that were previously undefined and assumed to be within the 40% contingency. Therefore, PG&E believes SCE did not eliminate its contingencies, but made individual estimates for many elements previously considered under contingency.

PG&E argues that the 40% contingency factor should be reduced only as it gets closer to the time that the actual work will be performed and costs become more certain, or as the components of potential contingencies are identified and separately estimated, as appears to be the case with SONGS 2&3. This is the reason it is recommending a 30% contingency factor for Humboldt early decommissioning.

ORA recommends that the Commission adopt TLG's estimated contingency factors. ORA says that TLG applied individual activity contingency

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[10] Engineering contingencies include such things as weather related delays and costs, personnel turnover, adverse working conditions, unrecorded construction modifications, previously undetected radioactive contamination, etc.

factors of 10% to 75% to arrive at its estimates, as opposed to PG&E's 30% or 40% overall contingency factor. ORA argues that Diablo Canyon and SONGS 2&3 are roughly of the same vintage, and the utilities have been able to reduce the SONGS 2&3 contingency factor from 40% to 21%. ORA asserts that a reduction in the contingency factor is appropriate because of developments in industry-wide experience.

Discussion

PG&E's overall contingency factors for Diablo Canyon, and Humboldt, accommodate engineering, financial, regulatory, and industry uncertainties in the initial cost estimate. The contingency factors estimated by TLG for PG&E address only engineering contingencies. Because the TLG contingency factors do not address all of these contingencies, we will not adopt ORA's recommendation of 17.95% to 21% overall contingency factors for these units.

We note that SCE has utilized its decommissioning experience and knowledge to refine its estimate for SONGS 2&3.[11] These refinements led to a reduction in uncertainty, and therefore, a reduction in the overall contingency factor to 21%. PG&E has access to much of the same industry information as SCE. We expect that PG&E availed itself of this information and experience to produce its decommissioning cost estimates. This suggests that a contingency factor lower than 40% is appropriate. SONGS 2&3 and Diablo Canyon are estimated to begin decommissioning at about the same time. This too suggests a lower contingency factor. PG&E's estimate has not been refined to the same level as the Utilities' estimate for SONGS 2&3. As a result, the uncertainty in

[11] The estimate was developed by SCE, but used by both SCE and SDG&E.

PG&E's estimate has not been reduced to the same degree for Diablo Canyon. Therefore, the 21% contingency factor used for SONGS 2&3 would be inappropriate for Diablo Canyon.

For the above reasons, we believe that PG&E's proposed overall contingency factor of 40% for Diablo Canyon is too high. The range of proposed contingency factors is 17.95% to 40%. Were we to give equal weight to PG&E and ORA's recommendations, we would adopt the midpoint of the range of 29%. However, ORA's proposed use of the engineering contingency factors estimated by TLG as the overall contingency factor does not address all of the contingencies the contingency factor is intended to cover. Therefore, we will give greater weight to PG&E's estimate. As a result, we will adopt a 35% overall contingency factor for Diablo Canyon.

As to Humboldt, we note that PG&E's request is based on early decommissioning for which it has reduced its contingency factor to 30%. Here too, PG&E has access to much of the same industry information as SCE. We expect that PG&E availed itself of this information and experience to produce its decommissioning cost estimates. In addition, with early decommissioning of Humboldt scheduled to start in 2006, we expect there to be substantially less uncertainty than for Diablo Canyon or Palo Verde, since they will all begin decommissioning much later. Therefore, a lesser contingency factor is appropriate. As to SONGS 2&3, they also will begin decommissioning much later than Humboldt. This tends to support a contingency factor closer to the 21% contingency factor used for SONGS 2&3. PG&E's estimate has not been refined to the same level as the utilities' estimate for SONGS 2&3. As a result, the uncertainty in PG&E's estimate has not been reduced to the same degree for

Humboldt. Therefore, the 21% contingency factor used for SONGS 2&3 would be inappropriate for Humboldt.

For the above reasons, we believe that PG&E's proposed overall contingency factor of 30% for Humboldt early decommissioning is too high. The range of proposed contingency factors is 18.54% to 30%. Were we to give equal weight to PG&E and ORA's recommendations, we would adopt the midpoint of the range of 24%. However, ORA's proposed use of the engineering contingency factors estimated by TLG as the overall contingency factor does not address all of the contingencies the contingency factor is intended to cover. Therefore, we will give slightly greater weight to PG&E's estimate. As a result, we will adopt a 25% contingency factor for Humboldt.

VI. Conclusion

As discussed above, we have adopted the following modifications to PG&E's calculation of the decommissioning cost revenue requirements:

- A 24% turnover rate for equities in the qualified trusts.
- A 29% turnover rate for equities in the non-qualified trusts.
- A 10.5% pre-tax return on equities.
- A 6.0% pre-tax return on fixed assets.
- Escalation rates, except for LLRW burial costs, based on the most recent DRI forecasts in the record, using weighted averages, and no separate contingency factor.
- A 7.5% escalation rate for LLRW burial costs.
- LLRW burial costs of $200 per cubic foot.

- Contingency factors of 35% for Diablo Canyon, and 25% for Humboldt.

Based on the above modifications to the decommissioning cost calculation for Diablo Canyon, we find that its decommissioning trusts are fully funded. Therefore, we will not authorize a revenue requirement for Diablo Canyon decommissioning. Based on the above modifications to the decommissioning cost calculation for Humboldt, we adopt an annual revenue requirement of $18.450 million for Humboldt decommissioning for 2003. We also adopt an annual revenue requirement for Humboldt SAFESTOR O&M of $8.254 Million. This results in an overall annual revenue requirement of $26.704 million.

In addition to the above, we find that PG&E's $0.95 million expenditure for Humboldt decommissioning costs incurred above the $15.7 million authorized in Resolution E-3503 was reasonable, and PG&E should be allowed to use Humboldt decommissioning trust funds to pay for them. We also find that the $3.5 million and $3.85 million Humboldt decommissioning projects authorized in Resolution E-3737 should be reviewed for reasonableness in the next NDCTP, after they have been completed.

This decision should be effective immediately.

VII. Rate Proposal

PG&E proposes to implement the revenue requirement authorized in this proceeding on an equal cents per kilowatt-hour basis, consistent with D.00-06-034. ORA does not object to this proposal. D.00-06-034 requires that nuclear decommissioning costs be allocated on an equal cents per kilowatt-hour basis. Therefore, we will require PG&E to implement the revenue requirement adopted herein on an equal cents per kilowatt-hour basis.

VIII. Procedural Matters

In Resolution ALJ 176-3085, dated April 4, 2002, the Commission preliminarily categorized this application as ratesetting, and preliminarily determined that hearings were necessary. Hearings were held on September 16 and 17, 2002.

IX. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed by PG&E, ORA and the Surfrider Foundation. All comments were considered. PG&E raises a few points that should be addressed.

After this matter was submitted, the Commission approved an offset to the nuclear decommissioning revenue requirement of approximately $10 million (Resolution E-3823). PG&E asks that the offset, and the revenue requirement change adopted herein, be implemented in Investigation (I.) 02-04-026. We expect to be addressing PG&E's revenue requirement in I.02-04-026, the Commission's investigation into PG&E's bankruptcy. Therefore, we will address implementation of the revenue requirements adopted herein, and in Resolution E-3823, in I.02-04-026.

PG&E will need to request a revised Schedule of Ruling Amounts from the federal Internal Revenue Service (IRS) in order to implement this decision. To facilitate obtaining a favorable ruling from the IRS, PG&E asks that tables showing the results of operations, assumptions, and fund disbursements adopted herein be included in this decision. The request is reasonable, and we will grant it. The tables are included as Attachment A.

X. Assignment of Proceeding

Geoffrey F. Brown is the Assigned Commissioner and Jeffrey P. O'Donnell is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Early decommissioning of Humboldt is less costly than decommissioning starting in 2015.

2. The decommissioning cost studies upon which PG&E's estimates for Diablo Canyon and Humboldt are based are unopposed except for contingency factors, escalation rates, rates of return, and LLRW burial cost estimates.

3. PG&E's request for authority to recover $8.254 Million in Humboldt SAFESTOR O&M is unopposed.

4. PG&E's request to adjust the SAFESTOR O&M administrative, general, tax, and allocated common plant amounts in the calculation of decommissioning cost revenue requirements in its 2003 general rate case is unopposed.

5. PG&E's request for attrition for the SAFESTOR O&M for 2004 and 2005 is unopposed.

6. PG&E has already commenced early decommissioning activities at Humboldt.

7. In Resolution E-3503, the Commission authorized PG&E to spend $15.7 million on three decommissioning projects, and found it reasonable to use the decommissioning trust funds to finance them.

8. In Resolution E-3737, the Commission found it reasonable to use the decommissioning trust funds to finance three proposed projects. The $3.5 million and $3.85 million projects were approved subject to review of the requested expenditures in this proceeding. The request for approval of the $0.95 million project was denied until reviewed in this proceeding.

9. PG&E's request to use the Humboldt decommissioning trusts to pay for the $0.95 million project is unopposed.

10. The $3.5 million and $3.85 million projects have not been completed.

11. For 1999 through 2002, PG&E's annual equity turnover rate ranged from 18% to 27% for qualified trusts, with an average of 24%. For 2000 through 2002, its annual equity turnover rate ranged from 18% to 49% for non-qualified trusts with an average of 29%.

12. PG&E has given us no reason to believe that future equity turnover rates will be substantially different from recorded turnover rates.

13. In D.00-02-046, the Commission adopted a forecast of an 11% pre-tax return on equities, and a 7% pre-tax return on the fixed income portion of PG&E's trusts.

14. No participant has indicated specifically how differences in decommissioning trust portfolios, and investment committee risk tolerances are incorporated into its rate of return estimates.

15. The three utilities' trusts will have access to the same equities markets, with the same investment opportunities.

16. While there is merit in using long-term historical data for estimating rates of return, selection of which data to use can give quite different results.

17. The DRI forecasts, which SDG&E and SCE use in different ways, yield much lower returns than the historical data used by PG&E and ORA.

18. No participant has demonstrated that its estimate of pre-tax returns on equities is better than the other participant's estimates.

19. Since the midpoint of the pre-tax returns on equities recommended by the participants is lower than the 11% pre-tax return on equities adopted in D.00-02-046, a reduction in the pre-tax return on equities is appropriate.

20. A 10.5% pre-tax return on equities is slightly above the midpoint of the range of values proposed by the participants.

21. No participant has demonstrated that its estimate of pre-tax returns on fixed assets is better than the other participant's estimates.

22. Since the midpoint of the pre-tax returns on fixed assets recommended by the participants is lower than the 7% pre-tax return on fixed assets adopted in D.00-02-046, a reduction in the pre-tax return on fixed assets is appropriate.

23. A 6.0% pre-tax return on fixed assets is slightly above the midpoint of the range of values proposed by the participants.

24. The Commission adopted a 7.5% LLRW burial cost escalation rate for PG&E in D.00-02-046.

25. The NRC data shows rapidly increasing LLRW burial costs followed by large, discrete jumps.

26. The utilities did not include a separate contingency factor in their calculation of escalation rates.

27. Since PG&E's unweighted calculation of escalation rates gives a 20% weighting to each of the five escalation categories, while the equipment and materials category accounts for 29%, and the "other" category accounts for 6% of actual expenditures, PG&E's use of a simple unweighted average is inaccurate.

28. The participants agree that a DRI forecast should be used in forecasting escalation rates, except for LLRW burial cost escalation.

29. ORA's DRI forecasts are the most recent in the record.

30. When using DRI forecasts to estimate escalation rates, use of the value for the last forecasted year for subsequent unforecasted years gives additional weight to the last forecasted year.

31. There is no reason that the DRI forecast for the last forecasted year is any better than the forecast for other years.

32. The Commission adopts contingency factors for cost estimates when the work to be done, and the requirements that must be met to do the work, may change substantially over time.

33. The escalation rate is an estimate of the rate of change in the cost of specified work.

34. The Commission routinely adopts forecasts of cost increases, in general rate cases for example, without applying contingency factors.

35. Since the risk of substantial changes in the work to be done and the requirements that must be met to do the work is covered by the contingency factor applied to the decommissioning cost estimate, there is no reason to apply a separate contingency factor to the calculation of the escalation rate.

36. The NRC LLRW burial cost data shows significant jumps, and has no data for some years.

37. ORA has not demonstrated that its recorded LLRW burial cost increases from 1996 to the present provide a better basis for estimation than the NRC data used by the utilities.

38. It is uncertain where the LLRW will be buried, and at what cost.

39. LLRW burial costs are no less certain now than they were when the Commission adopted a 7.5% LLRW burial cost escalation rate for PG&E in D.00-02-046.

40. No participant has demonstrated that its LLRW burial cost estimate is more accurate than the other participants' estimates.

41. The midpoint of the range of LLRW burial cost escalation rates proposed by the participants is 7.5%.

42. The facility at Barnwell, South Carolina, upon which PG&E's LLRW burial cost estimate is based, is going to stop accepting wastes from non-Atlantic Compact generators such as PG&E, SCE, and SDG&E.

43. The midpoint of the range of LLRW disposal costs proposed by the parties is $240 per cubic foot.

44. The utilities have done a more comprehensive analysis of decommissioning costs, especially for SONGS 2&3, than PG&E.

45. The decommissioning cost study for Palo Verde was prepared by the same consultant that prepared PG&E's decommissioning cost studies.

46. PG&E's contingency factors for Diablo Canyon and Humboldt accommodate engineering, financial, regulatory, and industry uncertainties in the initial cost estimate, while the TLG contingency factor addresses only engineering uncertainties.

47. SCE has utilized its decommissioning experience and knowledge to reduce the contingency factor to 21% for SONGS 2&3.

48. PG&E has access to much of the same industry information as SCE.

49. PG&E availed itself of industry information and experience to produce its decommissioning cost estimates.

50. The fact that SONGS 2&3 are estimated to begin decommissioning in 2022, and Diablo Canyon is estimated to begin decommissioning in 2021-2025, suggests the use of a contingency factor for Diablo Canyon of less than 40%.

51. PG&E's Diablo Canyon decommissioning cost estimate has not been refined to the level of the utilities' estimate for SONGS 2&3.

52. PG&E's 30% contingency factor for Humboldt is based on early decommissioning.

53. With early decommissioning of Humboldt scheduled to start in 2006, there should be substantially less uncertainty than for Diablo Canyon or Palo Verde, since they will all begin decommissioning much later.

54. Since SONGS 2&3 will begin decommissioning much later than Humboldt, a contingency factor closer to 21% is appropriate.

55. Since decommissioning planning for Humboldt has not been done to the same level of detail as for SONGS 2&3, use of a 21% contingency factor for Humboldt would be inappropriate.

56. PG&E's proposal to implement the revenue requirement adopted herein on an equal cents per kilowatt-hour basis is unopposed.

Conclusions of Law

1. PG&E's recommended early decommissioning of Humboldt should be adopted.

2. PG&E's request for authority to recover $8.254 Million in Humboldt O&M should be granted.

3. PG&E's request for authority to adjust the administrative, general, tax, and allocated common plant amounts in the calculation of Humboldt O&M expenses in its 2003 general rate case should be granted.

4. PG&E's request for attrition for SAFESTOR O&M for 2004 and 2005 should be granted.

5. The $0.95 million expenditure for Humboldt decommissioning costs incurred above the $15.7 million authorized in Resolution E-5303 was reasonable, and PG&E should be allowed to recover the costs from the trusts.

6. The $3.5 million and $3.85 million projects authorized in Resolution E-3737 should be reviewed for reasonableness in the next NDCTP, after they have been completed.

7. The Commission should adopt a 24% turnover rate for equities in the qualified trusts, and 29% for equities in the non-qualified trusts. For any year in which a higher amount of equities will need to be sold to pay for decommissioning costs, the higher amount should be used.

8. The Commission should adopt a uniform set of rate of return projections for all PG&E, SCE, and SDG&E.

9. D.99-06-007 approved a settlement and, therefore, is not a precedent.

10. The Commission should adopt a 10.5% pre-tax return on equities.

11. The Commission should adopt a 6.0% pre-tax return on fixed assets.

12. Since PG&E's actual expenditures do not support use of a simple average in determining escalation rates, and the utilities use a weighted average, the Commission should require the use of a weighted average.

13. Although forecasts of the future are speculative by nature, it makes sense to use the most recent available forecasts in estimating escalation rates.

14. The Commission should adopt the DRI forecasts used by ORA, which are the most recent DRI forecasts in the record, for use in determining escalation rates.

15. When using DRI forecasts for estimating escalation rates, the average rate for the forecast period should be used for the subsequent unforecasted years.

16. The Commission should not adopt a separate contingency factor for escalation rates where one is already applied to the decommissioning cost estimate.

17. NRC LLRW burial cost data does not provide a good basis for estimating LLRW burial cost escalation.

18. The Commission should adopt a 7.5% escalation rate for LLRW burial costs.

19. Future LLRW burial costs are uncertain at best.

20. PG&E's estimate of LLRW burial costs is no better than the estimates prepared by the utilities.

21. Actual LLRW burial costs will lie within the range of estimates proposed by the participants.

22. The Commission should adopt a LLRW burial cost estimate of $200 per cubic foot.

23. The Commission should adopt a 35% contingency factor for Diablo Canyon.

24. The Commission should adopt a 25% contingency factor for Humboldt.

25. Since PG&E's decommissioning trusts for Diablo Canyon are sufficient to cover the estimated decommissioning costs, no revenue requirement should be authorized for Diablo Canyon decommissioning.

26. The Commission should authorize annual revenue requirements of $18.450 million for Humboldt decommissioning, and $8.254 million for Humboldt SAFSTOR O&M.

27. This decision should be effective immediately.

28. D.00-06-034 requires that decommissioning costs be allocated on an equal cents per kilowatt-hour basis.

29. The revenue requirement adopted herein should be implemented on an equal cents per kilowatt-hour basis.

30. Implementation of the revenue requirement changes adopted herein, and in Resolution E-3823, should be addressed in I.02-04-026.

ORDER

IT IS ORDERED that:

1. Annual revenue requirements of $18.450 million for decommissioning Humboldt Bay Power Plant Unit 3 (Humboldt), and $8.254 million for Humboldt SAFSTOR operations and maintenance expenses are adopted for 2003.

2. No revenue requirement is authorized for decommissioning Diablo Canyon Nuclear Power Plant Units 1 and 2.

3. Pacific Gas and Electric Company (PG&E) shall implement the revenue requirements adopted herein on an equal cents per kilowatt-hour basis.

4. Implementation of the revenue requirement changes adopted herein, and in Resolution E-3823, shall be addressed in Investigation 02-04-026.

5. PG&E's request for attrition for its SAFESTOR O&M expenses in the amounts of $218,000 for 2004, and $230,000 for 2005 is granted.

6. PG&E's request for authority to adjust the administrative, general, tax, and allocated common plant amounts in the calculation of Humboldt SAFESTOR operation and maintenance expenses in its 2003 general rate case is granted. The amount of any such adjustment shall be determined therein.

7. The $0.95 million expenditure for Humboldt decommissioning incurred above the $15.7 million authorized in Resolution E-5303 is reasonable, and PG&E is authorized to recover the costs from the Humboldt decommissioning trusts.

8. The $3.5 million and $3.85 million Humboldt decommissioning projects authorized in Resolution E-3737 shall be reviewed for reasonableness in the next nuclear decommissioning cost triennial proceeding, after they have been completed.

9. This proceeding is closed.

This order is effective today.

Dated October 2, 2003, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I dissent.

/s/ CARL W. WOOD
Commissioner

I reserve the right to file a dissent.

/s/ LORETTA M. LYNCH
Commissioner

D0310014 Attachment A

ATTACHMENT A

Tables

for

Internal Revenue Service

Revised Schedule of Ruling Amounts

ATTACHMENT A

Pacific Gas and Electric Company
Electric Department
Results of Operations at Proposed Rates
Humboldt Nuclear Decommissioning Services
Year 2004, 2005
(Thousands of Dollars)

Line No.	Description	CPUC	FERC	Total	Line No.
		(A)	(B)		
	REVENUE:				
1	Revenue at Effective Rates	32,738	19	32,757	1
2	Less Non-General Revenue	0	0	0	2
3	General Rate Case Revenue	32,738	19	32,757	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Other Production	0	0	0	5
6	Storage	0	0	0	6
7	Transmission	0	0	0	7
8	Distribution	0	0	0	8
9	Customer Accounts	0	0	0	9
10	Uncollectibles	110	0	110	10
11	Customer Services	0	0	0	11
12	Administrative and General	0	0	0	12
13	Franchise Requirements	207	0	207	13
14	Project Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	0	0	0	17
18	Subtotal Expenses:	317	0	317	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	0	0	0	20
21	Payroll	0	0	0	21
22	Business	0	0	0	22
23	Other	0	0	0	23
24	State Corporation Franchise	1,833	(0)	1,833	24
25	Federal Income	7,258	(0)	7,258	25
26	Total Taxes	9,091	(0)	9,091	26
27	Depreciation	0	0	0	27
28	Fossil Decommissioning	0	0	0	28
29	Nuclear Decommissioning	23,473	19	23,492	29
30	Total Operating Expenses	32,881	20	32,901	30
31	Net for Return	(144)	(0)	(144)	31
32	Rate Base	(1,574)	(1)	(1,575)	32
	RATE OF RETURN:				
33	On Rate Base	9.12%	9.12%	9.12%	33
34	On Equity	11.22%	11.22%	11.22%	34

NOTES
Line 32 – From Effects on Working Capital
CPUC Jurisdictional factor of .999173

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PACIFIC GAS AND ELECTRIC COMPANY
TABLE 5-2
Nuclear Decommissioning Expense
Adopted Escalation Rates (percentage change)

Line No.	Year	PG&E Labor	Materials	Contract Labor	Burial Costs	Other	Weighted Average Escalation Rate	Line No.
		(a)	(b)	(c)	(d)	(e)		
	Weight	21.52%	10.42%	20.30%	28.51%	19.25%		
1	2002	0.00	0.00	0.00	0.00	0.00	0.00	1
2	2003	2.90	1.09	3.79	7.50	2.39	4.11	2
3	2004	3.00	1.30	3.77	7.50	2.34	4.14	3
4	2005	2.90	1.40	3.71	7.50	2.38	4.12	4
5	2006	3.10	1.50	3.75	7.50	2.51	4.21	5
6	2007	3.20	1.55	3.79	7.50	2.65	4.27	6
7	2008	3.30	1.62	3.89	7.50	2.74	4.34	7
8	2009	3.40	1.54	4.00	7.50	2.80	4.38	8
9	2010	3.60	1.57	4.09	7.50	2.85	4.45	9
10	2011	3.80	1.64	4.20	7.50	2.92	4.54	10
11	2012	4.00	1.58	4.26	7.50	2.96	4.60	11
12	2013	4.10	1.61	4.16	7.50	2.96	4.60	12
13	2014	4.40	1.65	4.12	7.50	3.00	4.67	13
14	2015	4.50	1.70	4.11	7.50	3.03	4.70	14
15	2016	4.70	1.77	4.14	7.50	3.10	4.77	15
16	2017	4.70	1.91	4.32	7.50	3.25	4.85	16
17	2018	4.70	2.07	4.54	7.50	3.51	4.96	17
18	2019	4.60	2.21	4.54	7.50	3.72	5.00	18
19	2020	4.70	2.38	4.89	7.50	3.97	5.15	19
20	2021	4.50	2.47	5.10	7.50	4.21	5.21	20
21	2022	4.60	2.59	5.26	7.50	4.38	5.31	21
22	2023	4.40	2.74	5.34	7.50	4.49	5.32	22
23	2024	3.62	1.65	3.91	7.50	2.88	4.44	23
24	2025	3.62	1.65	3.91	7.50	2.88	4.44	24
25	2026	3.62	1.65	3.91	7.50	2.88	4.44	25
26	2027	3.62	1.65	3.91	7.50	2.88	4.44	26
27	2028	3.62	1.65	3.91	7.50	2.88	4.44	27
28	2029	3.62	1.65	3.91	7.50	2.88	4.44	28
29	2030	3.62	1.65	3.91	7.50	2.88	4.44	29
30	2031	3.62	1.65	3.91	7.50	2.88	4.44	30
31	2032	3.62	1.65	3.91	7.50	2.88	4.44	31
32	2033	3.62	1.65	3.91	7.50	2.88	4.44	32
33	2034	3.62	1.65	3.91	7.50	2.88	4.44	33
34	2035	3.62	1.65	3.91	7.50	2.88	4.44	34
[illegible]	[illegible]	[illegible]	1.65	3.91	7.50	[illegible]	4.44	35
36	2037	3.62	1.65	3.91	7.50	2.88	4.44	36
37	2038	3.62	1.65	3.91	7.50	2.88	4.44	37
38	2039	3.62	1.65	3.91	7.50	2.88	4.44	38
39	2040	3.62	1.65	3.91	7.50	2.88	4.44	39
40	2041	3.62	1.65	3.91	7.50	2.88	4.44	40
41								41
42				Simple average across all years			4.55	42
43								43
44								44

Notes:

(a) Forecast for PG&E labor provided by DRI/WEFA.

(b) Contract labor rates are based on the DRI/WEFA forecast of labor escalation rates for contract construction.

(c) Material rates are derived by taking a simple average of escalation rates of six industrial materials relevant to nuclear decommissioning activities. The forecasts for these indexes is provided by DRI/WEFA.

(d) Other is based on DRI/WEFA's forecast of the Consumer Price Index (CPI-U).

(e) The DRI/WEFA forecast extends to 2023. Escalation rates after 2023 are held constant at the the 2002-2023 average level forecast.

(f) Weights are based on relative expenditures of Humboldt Decommissioning

PACIFIC GAS AND ELECTRIC COMPANY
Table 5-5
Humboldt Bay Power Plant, Unit 3
Nuclear Decommissioning Costs
Adopted Assumptions for Analysis

Line No.	Type of Assumption		
1	Proposed method of decommissioning		SAFSTOR/DECON IN 2006
2	Year in which substantial decommissioning costs first will be incurred		Three partial decommissioning projects in 1997-1999; dismantlement to begin in 2006.
3	Year in which substantial decommissioning will be substantially complete		2009
4	Total Cost of decommissioning ($2002)		$309,223,156
5	Total cost of decommissioning ($future nominal)		$377,116,379
6	For each year between 2 and 3 above, the annual cost of decommissioning ($future nominal)		see Table 5-6
7	After-tax annualized rate of return	Qualified Trust	Non-Qualified Trust
		2003 through 2004 - 6.69%	2003 through 2004 - 5.97%
		2005 - 6.50%	2005 - 5.63%
		2006 - 5.88%	2006 - 4.82%
		2007 - 5.33%	2007 - 4.22%
		2008 - 4.85%	2008 - 3.79%
		2009 - 4.46%	2009 - 3.51%
		2010 through 2015 - 4.16%	2010 through 2015 - 3.38%
8	Period over which decommissioning costs will be included in cost of service		October 2, 2003 through December 31, 2005
9	Projected amount to be included in cost of service	2003	$5,873,107
		2004-2005	$23,492,427
10	Date on which plant will no longer be included in rate base		N/A
11	Frequency of deposit in external fund		Variable
12	Projected fund balance on January 1, 2003		$177,880,000

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PACIFIC GAS AND ELECTRIC COMPANY
TABLE 5-6
Humboldt Bay Power Plant Unit 3
Nuclear Decommissioning Costs

Adopted Cash Flow Analysis
Includes Construction of Dry Cask Storage Facility; Decommissioning to begin in 2006
(in Millions of Dollars)

Year	Qual Fund YE Bal Before +/-	Next year Taxable Growth rate Q	Non-Qual YE Bal Before +/-	Next year Taxable Growth rate NQ	Q + NQ YE Value of Assets Before +/-	Contributions (NQ) w/25% [illegible]	Qualified W/drawal	Funds fr. NQ & Tax Savings	Non-Qual W/drawal	Corporate Tax Savings	Liquidation Cap Gain Qual	Liquidation Cap Gain NonQual	[illegible] (of YE)	Qualified Contrib.	Non-Qual Contrib.	NQ Trust First: Remaining Q Assets	Remaining NQ Assets	Remaining Assets
Ud [illegible] 12/3[illegible]	[illegible]		[illegible]													Excess/(Shortfall):		0.0
																Inflation rate		
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			92.2	85.7	177.9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	1.3	0.8	[illegible]	0.00	0.00	5.67	2.94	2.94	101.3	93.0	194.3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	36.6	21.7	[illegible]	0.00	-0.03	23.49	11.75	11.76	119.6	88.3	207.9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	212.1	[illegible]	0.0	85.6	36.8	[illegible]	0.00	-0.64	23.49	11.75	11.75	138.4	64.8	203.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	78.8	46.8	[illegible]	-0.36	-1.20	0.00			145.4	19.8	165.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	42.4	34.6	20.5	[illegible]	-1.09	0.00	0.00			109.0	0.0	109.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	75.4	0.0	0.0	[illegible]	-0.88	0.00	0.00			37.5	0.0	37.5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	15.9	0.0	0.0	[illegible]	0.00	0.00	0.00			23.1	0.0	23.1
2010	24.1	1.0416	0.0	1.0336	24.1	4.0	4.0	0.0	0.0	[illegible]	0.00	0.00	0.00			20.1	0.0	20.1
2011	20.8	1.0416	0.0	1.0336	20.9	4.2	4.2	0.0	0.0	[illegible]	0.00	0.00	0.00			16.7	0.0	16.7
2012	17.4	1.0416	0.0	1.0336	17.4	4.4	4.4	0.0	0.0	[illegible]	0.00	0.00	0.00			12.9	0.0	12.9
2013	13.6	1.0416	0.0	1.0336	13.6	4.7	4.7	0.0	0.0	[illegible]	0.00	0.00	0.00			8.8	0.0	8.8
2014	9.2	1.0416	0.0	1.0336	9.2	4.9	4.9	0.0	0.0	[illegible]	0.00	0.00	0.00			4.3	0.0	4.3
2015	4.5	1.0416	0.0	1.0336	4.5	4.5	4.5	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2016	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2017	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2018	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2019	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2020	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2021	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2022	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
2023	0.0	1.0416	0.0	1.0336	0.0	0.0	0.0	0.0	0.0	[illegible]	0.00	0.00	0.00			0.0	0.0	0.0
Total						377.1												

* Reflects liquidated value of actual account balances

**To calculate the total revenue requirement, the non-qualified trust contribution must be adjusted for tax to derive the revenue amount collected from ratepayers.

Note: Q=Qualified Fund, NQ=Non-Qualified Fund, AT ROR=After Tax Rate of Return
Before+/- = Before Adding or Subtracting Fund Return or Decommissioning Costs Incurred During that Period, YE=Year End

(END OF ATTACHMENT A)