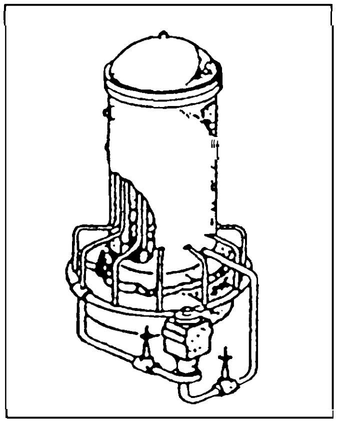
Case Studies of Nine Operating Plants 5

In order to learn in detail some of the current plans, activities, costs, and other issues related to commercial nuclear power plant life attainment, life extension, and decommissioning, the Office of Technology Assessment supported a study to examine five sites with nine operating plants.[1] This chapter is adapted from that study. The issues examined were performance and operating history, plans and activities towards license renewal, and current plans for decommissioning. The selected units span a wide range of ages, sizes, and designs, reflecting the diversity of the 108 nuclear power plants operating in the United States today.

The Frost step was to select plants for review that were representative of the diversity of U.S. nuclear power plants and that had experience with life attainment, license renewal, and decommissioning. To capture some of the diversity in plant designs, reactors from three of the four commercial nuclear suppliers were chosen. General Electric exclusively supplies boiling water reactors (BWRs), while there are three suppliers of pressurized water reactors (PWRs), Westinghouse, Combustion Engineering, and Babcock and Wilcox.

In addition, plants with a range of power capacities and ages were selected. A number of older plants, such as Oyster Creek and San Onofre Unit 1, were designed and constructed before substantial experience was obtained with commercial nuclear power. These older plants do not have the same kinds of systems and equipment found in larger and more *recently* constructed plants, but some face early decommissioning or life extension decisions now.



[1] ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning,' contractor report prepared for the Office of Technology Assessment, February 1993.

Under these considerations, the five sites selected were Calvert Cliffs, Hope Creek, Monticello, Salem, and the San Onofre Nuclear Generating Station (SONGS). Calvert Cliffs is a two-unit site with 845 megawatt-electric (MWe) Combustion Engineering reactors that both began operations in the mid-1970s. Salem is also a two-unit site, but with Westinghouse reactors, each rated at 1,106 MWe. Salem Unit 1 began operation in June 1977, and Unit 2 began operation in October 1981. The start delay between the units was caused primarily by the performance of upgrades (backfits) required after the accident at Three Mile Island Unit 2.

Hope Creek is a 1,031-MWe General Electric reactor that began operation in December 1986. The unit is a fourth generation BWR with enhanced safety features similar to the most current (sixth) generation. Earlier BWR designs such as Oyster Creek and Nine Mile Point Unit 1 are second and third generation units. The majority of BWRs are fourth and fifth generation plants similar to Hope Creek. Monticello is a third generation BWR and, until recently, was the industry's lead plant for license renewal. In terms of systems and design, Monticello is reasonably representative of the later BWR product line built in the 1970s.

The SONGS site has three units. SONGS Unit 1 is one of the first Westinghouse PWRs; the unit went on line in 1967 and was retired in 1992 pursuant to an agreement with the California Public Utilities Commission. SONGS Units 2 and 3 are larger, Combustion Engineering plants that went into service in the mid-1980s.

Despite an abundance of publicly available information, many details about commercial nuclear power plants contained in Federal Government and other reports are missing, elusive, or difficult to interpret. For example, detailed breakdowns of utility operations and maintenance (O&M) expenses are not publicly available and would be difficult to reconstruct; consequently, significant additional research and analysis would have been necessary to understand in detail the underlying causes for the rise in O&M costs over the past several years at these plants. In addition, the U.S. Nuclear Regulatory Commission (NRC) ranks operating plant performance by systematic assessment of licensee performance (SALP) scores, which range from 1 (good) to 3 (needs improvement). The impact of SALP scores on utility management is difficult to quantify, because the link between scores and subsequent corrective actions is difficult to trace with publicly available data.

CALVERT CLIFFS CASE STUDY[2]

Performance and Operating History

The Baltimore Gas and Electric Co. (BG&E) in Maryland owns and operates two nuclear power units at its Calvert Cliffs site. Both units are 845-MWe PWRs constructed by Bechtel. The nominal 40 year license period for both units has been established, recovering the time used for construction. BG&E applied for this extension in June 1984, and the NRC approved in May 1985. The recovered time used during construction enables both units to operate a total of 12 reactor-years beyond their original license periods. This action is consistent with industry practice. A summary of the construction and licensing history for Calvert Cliffs is listed in table 5-1.

Records indicate that BG&E operated both units at Calvert Cliffs in an above average manner until the late 1980s, with good reliability and safety records. Lifetime capacity factors for both units equal or slightly exceed industry averages. With the exception of scheduled outages, Calvert Cliffs did not experience significant outages until

[2] Unless noted otherwise, all information in the discussion of this plant is from personal communication between Baltimore Gas and Electric Co. (BG&E; Barth Doroshuk), ABZ, Inc. (Edward Abbott and Nick Capik), and the Office of Technology Assessment (Robin Roy and Andrew Moyad) on, and subsequent to, June 9, 1992.

Table 5-1—Calvert Cliffs Construction and Licensing History

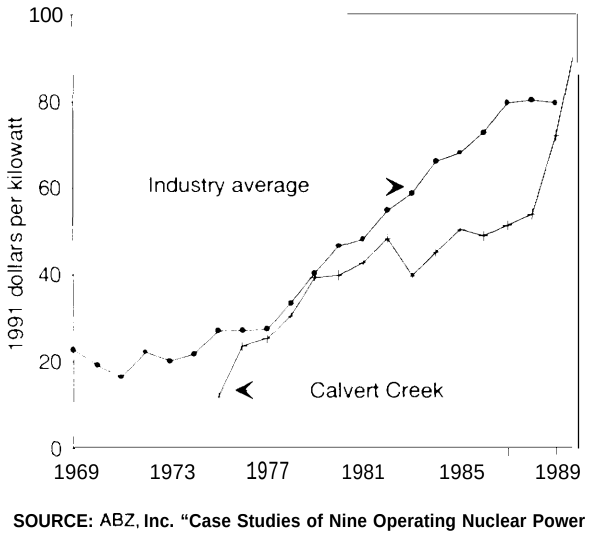
	Date of construction permit	Construction cost (year of expend iture, in millions)	Operating license start date	Commercial operation	License expiration	Lifetime capacity factor
Unit 1.	July 1969	$428.7	July 1974	May 1975	July 2014	67 percent
Unit 2.	July 1969	$329.7	November 1976	April 1977	April 2016	70 percent

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993

1989. BG&E held its operating and maintenance costs below the industry average until the late 1980s (figure 5- 1). With the exception of backfits performed between 1980 and 1983—largely in response to the Three Mile Island (TMI) accident—there were no major capital additions at Calvert Cliffs (figure 5-2). Other NRC performance indicators for Calvert Cliffs are summarized in table 5-2 (values are for both units combined). The lack of significant safety issues until the late 1980s helped BG&E maintain operating costs significantly below the industry average.

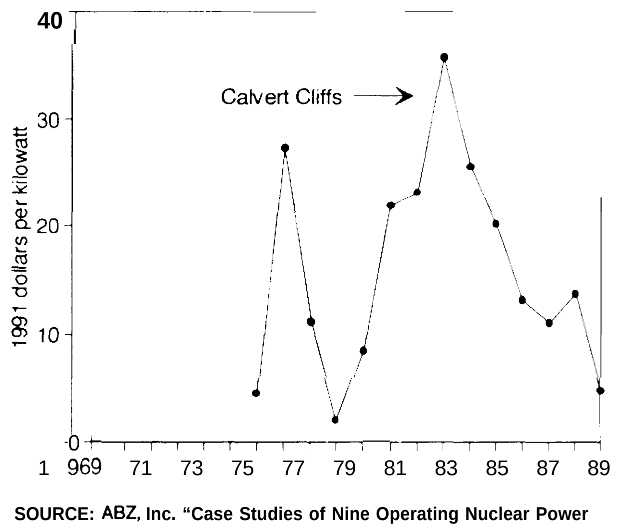
In the late 1980s, performance at Calvert Cliffs degraded significantly. First, BG&E identified several problems with engineering support and system maintenance. Second, the NRC fried the utility $300,000 in March 1988 for failing to certify the ability of certain electrical equipment to perform in cases of hot, wet, and high radiation conditions that could result from a severe accident. When informed of the violation, BG&E shut down Unit 1 for 2 months to evaluate the problem. (Unit 2 was shut down at the time.) To remedy the problem, BG&E qualified or replaced most of the affected equipment.

Figure 5-1—Calvert Cliffs Non-Fuel Operation and Maintenance Costs (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Figure 5-2--Calvert Cliffs Capital Additions (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Table 5-2-Performance Indicators for Calvert Cliffs

	1985	1966	1987	1966	1889	1990	1991
Total scrams	7	7	8	4	0	0	2
Scrams > 15% per 1,000 hours	0.99	0.75	0.46	0.27	0	0	0.06
Scrams < 15% per 1,000 hours	0	0.13	0.13	0	0	0	0.13
Safety system actuations	2	1	2	4	2	2	1
Significant events	5	2	8	2	2	0	0
Safety system failures	7	1	4	0	7	8	5
Forced outage rates (%)	5.67	3.38	5.13	1.75	1.88	1.88	9.38
Equipment forced out per 1,000hours	1.01	0.60	0.70	0.25	0.24	0	0.54
Critical hours	8,017	15,348	12,554	14,249	3,573	1,925	6,687

SOURCE: ABZ, Inc., "Case Studies of Nine operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

BG&E performance during this period led the NRC to add Calvert Cliffs to its "Problem Plants" list, which increases NRC oversight. In 1989, BG&E was freed an additional $75,000 for violations involving management oversight and the control of plant activities. In March 1989, Unit 2 was shut down after BG&E discovered cracks in its pressurizer heater sleeves. Subsequent analysis determined intergranular stress corrosion cracking (IGSCC) as the cause. Unit 1 continued operating until its next planned refueling shutdown that May, but subsequent inspections found no evidence of IGSCC in that unit as well. BG&E suspected that the Unit 2 heater sleeves were more susceptible to IGSCC, because they were reamed (enlarged) during manufacturing to ease the installation of heater elements.[3] Replacement power costs during the resulting outage were estimated at $300,000 per unit per day. In part from uncertainty about the utility's restart schedule, as well as uncertainty over recovery of replacement power costs, BG&E's credit ratings were downgraded.

Due to declining performance in the late 1980s and uncertainty related to the heater sleeve cracking, the NRC issued a confirmatory action letter in 1989 preventing the restart of both units. The utility was required to develop corrective action plans for NRC approval. The units were shutdown for several months, after which time the NRC approved the BG&E plan. The corrective action stipulated procedural upgrades and increased training. These actions, as well as the increased maintenance that occurred during the shutdown, led to a significant increase in O&M costs.

Of the nearly 100 licensee event reports (LERs) submitted to the NRC by BG&E since 1988, the NRC rated 3 as significant events, down from the average number of significant events reported in prior years. Table 5-3 summarizes the 3 significant events at Calvert Cliffs that occurred between 1989 and 1991. In addition, the problems at Calvert Cliffs in the late 1980s are reflected by poor SALP scores during this period. These scores began improving in late 1989 when the NRC noted a substantial change in management attitude that led to aggressive efforts to improve performance. Complete SALP data for Calvert Cliffs are summarized in table 5-4. Notably, the problems of the late 1980s did not have a clear effect on NRC performance indicators at Calvert Cliffs, with the exception of a decline in critical hours.

BG&E is planning or considering several major capital improvements, including the addition of three diesel generators and steam generator replacements. Revised NRC guidance on station blackout accidents prompted the addition of the diesel generators; estimated costs are $130

[3] *Nucleonics Week,* vol. *30, No. 36,* Sept. *7, 1989.*

million. BG&E has no definite plans for steam generator replacement but will monitor the performance and material condition of the existing units. Estimated costs are $100 million to $200 million per unit, excluding replacement power charges. A decision on steam generator replacement will probably be deferred until BG&E decides whether to pursue license renewal.

During a recent (June 1992) maintenance outage, BG&E employed 1,100 contractors to supplement the 1,400 permanent staff at Calvert Cliffs. The contractor support is expected to decrease to roughly 400 after the outage. Approximately 50 of these remaining 400 contract staff provide unarmed security to supplement the armed BG&E force. The growth in BG&E's permanent staff from a low of about 200 in the late 1970s to its current number stems from several factors, including increased regulatory requirements and the addition of an onsite engineering organization. BG&E's staffing levels are within the typical range for the industry. Increased contractor support during outages is primarily the result of additional craft labor to perform outage-related work such as turbine overhaul, periodic inspections, and major system modifications.

Life Attainment and License Renewal

Based on internal economic analyses, BG&E currently regards license renewal as desirable, but a final decision is not expected until 1999. In the meantime, the utility has implemented an integrated program to maintain the material condition of systems, structures, and components (SSCs) through the current and any renewed license terms. The goal of the program is to achieve good performance up to and possibly beyond the current plant lifetime, including any preparations for decommissioning. This life-cycle management program includes several phases:[4]

Table 5-3—Summary of Significant Events at Calvert Cliffs

Unit	Date	Description
Unit 2.	3/01/89	Failure of throttle trip valve in a turbine-driven auxiliary feed pump, with resulting control room fire.
Unit 2.	5/05/89	Boric acid buildup on pressurizer heaters.
Unit 2.	12/20/89	Licensee discovered nonsafety section of piping in service water system could rupture in an earthquake and thus interrupt the flow of safety-related service water to the auxiliary building and the emergency diesel generators.

SOURCE: ABZ, Inc., '(Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

- System screening to identify components either important to license renewal (ITLR) or important to power production (ITPP).
- Analysis of ITLR and ITPP components to identify life cycle management requirements for continued service.
- Evaluation of the effectiveness of existing programs in addressing life-cycle management issues.
- Implementation of new or modified programs and evaluation of the generic applicability of lessons learned.
- Review of existing plant maintainability and reliability. This phase includes an evaluation of potential major improvements that could lead to significant nuclear safety and personnel benefits.

This integrated program is intended to provide information needed to optimize life-cycle decisions. Program costs are $5 million per year, and $1 million is cofunded by the Electric Power Research Institute (EPRI). BG&E has finished reviewing one system (the salt water cooling system) and has begun to review four others: control room and switchgear heating, ventilating,

[4] Baltimore Gas and Electric Co., "Life Cycle Management Program," June 9, 1992.

Table 5-4-Summary of Calvert Cliffs SALP Scores

Assessment period	Plant operations	Radiological controls	Maintenance/ surveillance	Emergency preparedness	Engineering Security	technical support	Safety assessment/quality verification
1/90-3/9.	2	2	2	2	1	2	2
12/88-12/89.	3	2	3	2	1	2	3
9187-1 1/88.	2	1	2	2	1	2	3

Assessment period	Plant operations	Radiological controls	Maintenance	Surveillance	Fire protection	Emergency preparedness	Security	Outages	Quality programs and administrative controls effecting quality	Licensing activities	Training and qualification effectiveness
5/86-8/87.	2	1	2	2	N	2	1	1	2	2	2
1O/84-4/86.	2	1	2	1	N	1	1	2	2	1	2
1O/83-8/84.	1	1	2	2	1	1	1	1	N	1	N
10182-9/63.	2	2	3	3	1	2	1	2	N	2	N
10181 -9182.	2	1	2	1	1	1	2	1	N	2	N
10179-9180	3	2	3	2	2	2	3	2	3	N	N

NOTE: Category 1 indicates superior performance, where reduoed NRCattention maybe appropriate; Category2 indicates good performance and a recom mendation tornaintain normal NRC attention; Category 3 indicates acceptable performance, where NRC may consider increased inspections, andCategory N indicates insufficient information tosupportan assessment- As these categories suggest, the NRC SALP rankings include no failing grades.

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants; Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

and air conditioning (HVAC) systems; compressed air; containment structures; and the reactor coolant system including the reactor vessel. BG&E believes this program has already paid off by redirecting efforts to upgrade the salt water cooling system. Although the utility has not yet decided whether to pursue license renewal, information from the life cycle management program provides the foundation for a license renewal application.

A joint EPRI-BG&E project has addressed concerns about information storage retrieval for the plant. PC-based software was developed to ease the organization, storage, and retrieval of life cycle information. The system, named "LCMDATA" (for ''life cycle management data' '), will support evaluations of material conditions relevant to age-related degradation. Both text-based and graphical information can be stored and retrieved. The system will document evaluations and provide information to assist a license renewal application should BG&E decide to pursue one. BG&E may expand LCMDATA to track equipment covered by the recent NRC maintenance rule.

BG&E is currently concerned about potential reactor vessel embrittlement during a particular accident sequence at the end of plant life. Specifically, BG&E must demonstrate that embrittlement will not eliminate the margin of protection against Unit 1 vessel failure from a small-break, loss-of-coolant accident at the end of plant life, where vessel pressure remains high while the vessel downcomer is cooled by the safety injection system. Analysis of the Calvert Cliffs vessels indicates that Unit 2 is adequate for more than 60 years, but Unit 1 is projected to require further analysis to operate beyond 2005 (9 years *before* current license expiration). Different fabrication techniques and materials are responsible for the relative vulnerability of Unit 1 compared to Unit 2. While no decision has been made yet, BG&E is considering several solutions to the Unit 1 problem: demonstration of slower than assumed embrittlement; reduction in the neutron flux experienced by the vessel; modifications to heat the injection water; more thorough analysis to alleviate current concerns; or vessel annealing.

The utility intends to keep license renewal as an option, and in support of this effort, tailored the Integrated Plant Assessment requirement of NRC's License Renewal rule to the plant's service water system.[5] The NRC has informally recognized the life-cycle management program at Calvert Cliffs as an effective tool in the license renewal process. In the meantime, no additional NRC inspections or audits are anticipated beyond those that are standard for the industry. Other than the programs discussed above, there are no other significant research efforts at Calvert Cliffs, except those performed by the industry through groups such as EPRI.

In 1989, BG&E applied for an NRC license to construct an independent spent fuel storage installation (ISFSI) at the Calvert Cliffs site to provide additional temporary spent fuel storage space until the U.S. Department of Energy (DOE) begins accepting the material.[6] ISFSI construction began in April 1991 and completion is scheduled for October 1992. The ISFSI will provide enough additional spent fuel storage space until 2003 at a cost of about $24 million, which includes $18 million for capital costs and $6 million for operations and maintenance. If more space is necessary-which would be the case if the DOE is not accepting spent fuel by 2003-additional space is authorized for operations until 2030.

[5] Stone and Webster Engineering Corp., and Baltimore Gas and Electric Co., Service *(Salt) Water System Life-Cycle Management Evaluation,* EPRI TR-102204 (Palo Alto, CA: Electric Power Research Institute, April 1993).

[6] Baltimore Gas and Electric Co., "Calvert Cliffs Nuclear Power Plant Independent Spent Fuel Storage Installation Project, Status Report,'' June 8, 1992.

Table 5-5-Hope Creek Construction and Licensing History

	Date of construction permit	Construction cost (year of expenditure, In millions)	Operating license start date	Commercial operation	License expiration	Lifetime capacity factor
Unit 1.	November 1974	$3,506.7	April 1986	December 1986	April 2026	81.9 percent

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Decommissioning

BG&E owns 100-percent, undivided interest in both Calvert Cliffs units. (When there are multiple owners of a nuclear power plant, decommissioning costs are generally divided according to the proportion of ownership.) In a 1990 letter to the NRC, BG&E noted its decision to use qualified external sinking funds to provide financial assurance for decommissioning both units.[7] Decommissioning costs of $137.3 million (1989 dollars) per unit were calculated using 10 CFR 50.75(c). Annual deposits to the external funds will amount to $5.5 million for Unit 1 and $5.1 million for Unit 2. (Each rate is based on the remaining lifetime of the respective unit.) In 1989, the Unit 1 fund was $414,165 below the required amount, and the Unit 2 fund was $2.4 million above the required amount. At the end of 1989, the Unit 1 trust fund held $5.1 million and the Unit 2 fund $7.5 million.

BG&E has made no formal plans for decommissioning but intends to begin investigating options in 1993. Because both Calvert Cliffs units have substantial time remaining in their operating licenses, BG&E considers decommissioning planning premature at present. No analysis of decommissioning options has been performed yet, and the impact of premature retirement or license renewal of either unit has not been analyzed. The lack of specific action towards these issues for units of this age is consistent with common industry practice.

HOPE CREEK CASE STUDY[8]

Performance and Operating History

Hope Creek is a relatively young 1,031-MWe BWR constructed by Bechtel and operated by the Public Service Electric and Gas Co. (PSE&G) in New Jersey. The single-unit plant is jointly owned by PSE&G (95 percent) and Atlantic City Electric (ACE) Co. (5 percent). The term of the operating license is based on 40 years from the date of approval, thus automatically recovering the construction period. A summary of the construction and licensing history for Hope Creek is listed in table 5-5.

Hope Creek's performance since its recent entry into commercial operation has been above the industry average. NRC reviews of the plant note a conservative, safety-conscious approach; a sound management philosophy; good administrative programs; and skillful personnel-all reflected by both the lack of serious NRC regulatory violations and good SALP ratings (table 5-6). The plant's critical operating time exceeds industry averages and operating costs have equaled or slightly exceed industry averages (figure 5-3). NRC performance measures reveal one problem area with Hope Creek relative to the industry

[7] Baltimore Gas and Electric Co., "Calvert Cliffs Nuclear Power Plant Units 1 and 2, Submittal of Certification of Financial Assurance for Decommissioning," letter dated July 24, 1990.

[8] Unless noted otherwise, all information in the discussion of this unit is from personal communication between the Public Service Electric and Gas Co. (PSE&G; James Bailey et al.), ABZ, Inc. (Edward Abbott and Nick Capik), and the Office of Technology Assessment (Robin Roy and Andrew Moyad) on, and subsequent to, June 1, 1992,

Table 5-6-Summary of Hope Creek SALP Scores

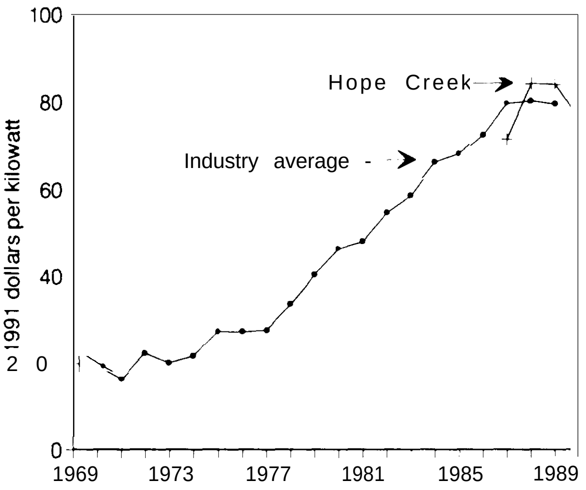
Assessment period	Plant operations	Radiological controls	Maintenance surveillance	Emergency preparedness	Engineering security	technical support	Safety assessment/qualit y verification
8/90-3/92.	1	1	2	1	1	1	1
5/89-7190.	1	1	2	1	1	1	1
1188-4189	1	1	2	2	1	2	2

Assessment period	Plant operations	Radiological controls	Maintenance	Surveillance	Fire protection	Emergency preparedness	security	Outages	Quality programs and administrative controls effecting quality	Licensing activities	Training and qualification effectiveness
1286-1/88.	2	2	1	2	N	1	1	N	2	2	1
11/85-1 1/86.	2	2	1	2	N	1	1	N	2	1	2

NOTE: Category 1 indicates superior performance, where reduced NRC attention maybe appropriate; Category 2 indicates good performance and a recommendation to maintain normal NRC attention; Category 3 indicates acceptable performance, where NRC may consider increased inspections, and Category N indicates insufficient information to support an assessment. As these categories suggest, the NRC SALP rankings include no failing grades.

SOURCE: ABZ, inc., "Case Studies of Nine Operating Nuclear Power Plants; Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1983.

Figure 5-3-Hope Creek Non-Fuel Operation and Maintenance Costs (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Ufe Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

(table 5-7). This area, the number of safety system failures, has recently been addressed by a comprehensive review performed by the utility.

Since commercial operation began in 1986, LERs have averaged 44 per year, which is above the industry average, but most occurred in the first 2 years of operation. PSE&G attributes this larger than average number to the reporting philosophy at Hope Creek, where events are reported that other utilities might not report. Consistent with this explanation, the NRC has classified only one LER in the past 5 years as significant. This single event is summarized in table 5-8.

PSE&G has 2,200 permanent staff working at its three units (Hope Creek and two Salem units), administrative offices, and training center (located nearby). In addition to this staff, contractors are hired for short-term projects, such as outage work. About 500 to 600 contractors are necessary to supplement the permanent staff for each unit outage. With no outage, only 200 to 300 contractors are needed. This permanent contractor group includes security personnel. In the mid-1980s PSE&G evaluated which contractor positions would be more appropriate for permanent staff. However, no data are readily available regarding the number of contractor positions eliminated, the increase in permanent staff positions, or the net effect on costs and performance.

Life Attainment and License Renewal

Although the Hope Creek plant is relatively new, PSE&G has initiated a Configuration Baseline Documentation Project to monitor the material condition of SSCs during the current and any renewed license terms. Part of the motivation for this long-term effort was a 52-day plant

Table 5-7—Performance Indicators for Hope Creek

	1986	1987	1988	1989	1990	1991
Total scrams	9	5	4	2	4	2
Scrams > 15% per 1,000 hours	0.55	0.7	0.25	0.16	0.55	0.41
Scrams < 15% per 1,000 hours	1.5	0	0	0	0	0
Safety system actuations	24	7	6	1	3	3
Significant events	2	1	0	0	0	0
Safety system failures	5	5	8	3	4	5
Forced outage rates	23	9.5	4,8	1.5	6.5	6.25
Equipment forced out per 1,000 hours	0.55	1.03	0.76	0.52	0.28	0.58
Critical hours	2,669	7,569	7,089	6,814	8,020	7,380

SOURCE: ABZ, inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology e NRC may consider increased inspections, and Category N indicates insufficient information to support an assessment. As these categories suggest, the NRC SALP rankings include no failing grades.
Assessment, February 1993.

shutdown at Salem caused by incomplete design information. Eighty-two systems at Hope Creek are involved in the project, which is scheduled for completion in 1998 at a total cost of $16 million (excluding any maintenance needs identified during the project). PSE&G claims this project has improved understanding about plant design, improved design control and engineering productivity, and formed a better foundation for evaluating potential design modifications. In addition, PSE&G considers this program part of the foundation for future considerations of license renewal.

No deficiencies have been identified that would preclude Hope Creek license renewal. Other than those in the current revitalization program, no significant capital additions are contemplated. No other activities related to license renewal are planned for the near future, and no significant research efforts are being undertaken. Finally, no additional NRC inspections or audits are anticipated other than those standard for the industry.

The Hope Creek operating license expires in 2026, but the unit's spent fuel pool has sufficient space for operations only until 2010. Although no plans have been made for additional temporary storage space, adequate space is available on the site if new facilities (i.e., dry storage) become necessary.

Table 5-8-Summary of Significant Events at Hope Creek

Date	Description
10/10/87.	Scram with safety relief valve stuck open during surveillance testing.

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Decommissioning

Hope Creek's two joint owners (PSE&G and ACE) will divide the decommissioning costs. In a 1990 decommissioning report submitted to the NRC, PSE&G estimated its share of decommissioning costs at $165.2 million (1990 dollars).[9] To reach this amount, PSE&G will deposit $4,6 million annually in a qualified external sinking fund. At the end of 1989, the PSE&G fund contained $13.9 million (1989 dollars). In its 1990 decommissioning report provided to the NRC, ACE estimated its share of the total escalated decommissioning cost at $8.7 million (1990 dollars), which is deposited into an external sinking fund at the rate of $226,000 per year.[10] The expected value of the ACE fund at the time of decommissioning is $13 million.

In addition to decommissioning reports submitted to the NRC, PSE&G has commissioned two site-specific cost estimates for Hope Creek. The frost study was performed by TLG Services, Inc. (TLG) in 1987 and estimated total costs at $350 million. A 1990 update by TLG increased the estimate to $450 million (1990 dollars) .[11] PSE&G claims that the increase is due to the added costs of on site spent nuclear fuel storage, increased labor rates, the development of more realistic schedules for decommissioning activities, higher low-level waste compaction and disposal charges, higher energy costs, and higher insurance costs. PSE&G estimates the disposal of radioactive waste will amount to 30 percent of the total cost and may be underestimated because of the uncertainty about the availability of disposal sites in the future. These studies have not been submitted to the NRC but are used as a basis for the rate base.

PSE&G has not evaluated the potential impact of early retirement for the Hope Creek facility.

[9] Public Service Electric and Gas Co., "Hope Creek Generating Station Report and Certification of Financial Assurance for Decommissioning, " July 1990.

[10] Atlantic Electric Co., ''Decommissioning Reports Relating to Atlantic Electric Company's Ownership Interests in Hope Creek, Peach Bottom Units 2 and 3, and Salem Units 1 and 2," letter dated July 26, 1990.

[11] At the time of this study, the decommissioning cost update was involved in a rate case and was not available fOr review.

The 1990 decommissioning studies assume a license period that recovers the construction period. At present, PSE&G has not analyzed the impact of license renewal on decommissioning planning or funding. This is consistent with industry practice.

The New Jersey State legislature is considering legislation that would require the periodic review of estimated decommissioning costs for nuclear generating stations in the State.[12] The intent of the bill is to assure that adequate funds are available for decommissioning at the end of plant operations. The bill includes reporting requirements for decommissioning trust funds to monitor their progress. The bill contains several significant provisions:

New Jersey utilities must file site-specific or site-adjusted decommissioning cost estimates by January 1, 1993, and every 3 years thereafter. Within 10 years of ending commercial operation, the filing interval is reduced to 18 months.

Decommissioning cost estimates must document the current status and developing trends for all activities that could affect decommissioning costs, including the following:

- actual decommissioning cost experience, both foreign and domestic;
- the development and use of state-of-the-art equipment and techniques, such as robotics, chemical cleaning methods, and waste processing methods;
- the development of both high-level and low-level radioactive waste disposal sites and their cost structures;
- transportation methods and hardware;
- applicable regulatory changes; and
- estimates of insurance costs.

Annual reports on decommissioning trust funds must be filed, documenting asset value, portfolio mix, achieved returns, earnings indices (for benchmarking trust fund performance), and applicable management fees. In addition, the New Jersey Board of Regulatory Commissioners must be notified of any changes in decommissioning trust fired agreements.

This legislation provides for a written comment period after information is submitted by utilities. After such period, the Board would determine whether funding levels require formal review prior to future base rate filings. If so, the Board would initiate proceedings, including a discovery process, rights of intervention, and public and/or evidentiary hearings.

MONTICELLO CASE STUDY[13]

Performance and Operating History

Monticello is a 545-MWe General Electric BWR constructed by Bechtel and owned and operated by the Northern States Power (NSP) Co. The single-unit plant entered commercial operation in January 1971, and the current license expires in September 2010. The 2010 date includes the recovery of the construction period, which extended the license 3 years. This extension was requested in February 1987 and granted by the NRC in November the same year. A summary of the construction and licensing history for Monticello is listed in table **5-9.**

Monticello reliability, as measured by length of critical operations, has consistently surpassed the industry average. Other performance indicators reveal no weaknesses or other noteworthy trends. Instead, these indicators and the periodic SALP reviews suggest consistent plant reliability, strong regulatory performance, and stable operations (table 5-10). There have been few significant events at Monticello; the NRC has recorded

12 New Jersey Board of Regulatory commissioners, ''Nuclear Generating Plant Decommissioning Proposed New Rules, '' letter dated Mar. 6, 1992.

13 Unless noted otherwise, all information in the discussion of this unit is from personal communication between Northern States Power Co. (NSP; Terry Pickens et al.), ABZ, Inc. (Edward Abbott), and the Office of Technology Assessment (Robin Roy) on, and subsequent to, Oct. 27, 1992.

Table 5-9—Monticello Construction and Licensing History

	Date of construction permit	Construct Ion cost (year of expenditure, In millions)	Operating license start date	Commercial operation	License expiration	Lifetime capacity factor
Unit 1.	June 1967	$119.1	January 1971	June 1971	September 2010	71.2 percent

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

only two in the last 5 years. These significant events are summarized in table 5-11. A summary of SALP scores for Monticello is listed in table 5-12.

Monticello O&M costs have been consistently above the industry average with year-to-year variations reflecting the added costs of refueling outages (figure 5-4). In contrast, plant capital additions have remained generally at or below industry averages (figure 5-5). In 1983, NSP replaced the stainless steel piping in the recirculation system and several connected branch systems at Monticello. This piping is used for reactivity control (i.e., control of reactor power during operation) and was replaced due to its vulnerability to IGSCC. Consequently, there was a large, one-time increase in capital additions.

NSP employs a staff of about 400 for all of Monticello activities, including corporate support and onsite personnel. Onsite staff numbers about 350: about 300 permanent employees and 50 contractors. To help control O&M costs, NSP has performed recent reorganizations to reduce the number of contractors and streamline the overall organization.

Life Attainment and License Renewal

Monticello was the second U.S. nuclear power plant to initiate an application for NRC license renewal as part of the lead-plant effort. NSP began the process in September 1988 and anticipated preparatory costs of about $40 million over 6 or 7 years. This estimate included company costs, NRC fees, contractor costs, legal expenses, and public relations and communications costs. Since 1988, NSP has spent about $9 million of its own funds and about $4.5 million of DOE and EPRI monies; thus, most of the funds budgeted for the license renewal application remain. In 1992, NSP announced an indefinite deferral of the filing of a license renewal application largely due to uncertainties interpreting the NRC license renewal rule and State concerns over spent fuel disposal. For example, NSP noted its concern that the number of reactor systems to be examined for

Table 5-10-Performance Indicators for Monticello

	1985	1986	1987	1988	1989	1990	1991
Total scrams.	3	2	4	1	2	1	4
Scrams > 15% per 1,000 hours.	0.48	0.23	0.48	0.11	0.32	0.12	0.47
Scrams <15% per 1,000 hours.	0	0	0	0	0	0	0.5
Safety system actuations.	0	2	1	0	1	0	3
Significant events.	0	3	1	0	0	1	1
Safety system failures.	0	4	3	0	6	2	6
Forced outage rates. , ...	0.67	0.75	1.5	0.25	1,75	2.5	4.25
Equipment forced out per 1,000 hours.	0.15	0.12	0.37	0.12	0	0	0.12
Critical hours. ., ...	6,427	6,984	7,174	8,769	6,679	8,487	7,076

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Table 5-n-Summary of Significant Events at Monticello

Date	Description
9/1 1/90.	Both emergency diesel generators were vulnerable to the potential failure of a nonseismic fire suppression pipe.
8/23191	The original analysis of internal flooding neglected to amount for the potential loss of the diesels and redundant trains of electric equipment. No other performance indicators were involved.

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

license renewal remained Unspecified, but had increased from 74 to at least 104.

Two technical issues have arisen in the Monticello license renewal process that have led to uncertainty over the practical interpretation of the license renewal rule. First, in accordance with 10 CFR 50.49, plant electrical equipment must be qualified to withstand the effects of an accident. Monticello currently complies with the rule by adhering to an Institute of Electrical and Electronics Engineers (IEEE) standard published in 1971. This standard, along with other documents, comprises the Monticello equipment qualification (EQ) program. The EQ program requires that, when replacing any electrical equipment, NSP must use equipment that is qualified based on a subsequent 1974 standard with stricter requirements. This process of gradual replacements and upgrades has been reviewed by the NRC, found acceptable, and become part of Monticello's current licensing basis. However, based on discussions with NRC staff, Monticello believes it may be required to upgrade to the 1974 standard as a condition for license renewal. NSP estimates that it would cost about $40 million, much of which would be spent analyzing plant cabling. NSP believes that most cabling would be found acceptable based on similar analysis done by Sandia Laboratories.

The second technical issue involves a potential upgrade to a piping code that requires consideration of the conditions ("environment") created by the fluid within the pipe. Monticello piping was qualified to an older American Society of Mechanical Engineers (ASME) code when the plant was constructed (ASME B31.1), whereas plants built today must comply with another code (ASME Section III). ASME is considering the inclusion of "environmental factors" in an upcoming revision of the code. As a result, NSP believes that the NRC staff will require such environmental factors to be included in their analysis of the adequacy of Monticello piping. NSP, based on discussions with one member of the code committee, believes that although not explicit in ASME B31. 1, the code does implicitly account for environmental factors. In addition, NSP contends that its own inservice inspection program would detect pipe cracking due to environmental factors before pipe failure. Given this inspection program and what it believes to be the adequacy of the current piping requirements, NSP believes upgrading to a yet unapproved standard to renew the license is not needed.

In both cases, the current licensing bases for Monticello are intended to provide an adequate level of safety for continued operation for the time remaining in the operating license. As such, NSP believes the license renewal rule does not require upgrading to new standards. The NRC staff, however, believes such upgrades can be imposed under the ''regulatory oversight" portion of the rule. NRC clarification is needed to resolve these technical issues. In the interim, the Monticello license renewal application has been indefinitely deferred.

Before Monticello's license can be extended, the spent fuel pool at the plant will require additional capacity. Without more fuel storage capacity operations will need to cease by 2005. (Currently, Monticello operates on 18 month fuel cycles.) NSP already expanded spent fuel storage capacity in 1978 with the addition of high-density fuel racks. The utility may extend the fuel cycle to 24 months and thereby extend the capacity of the fuel pool to 2010.

Table 5-12-Summary of Monticello SALP *Scores*

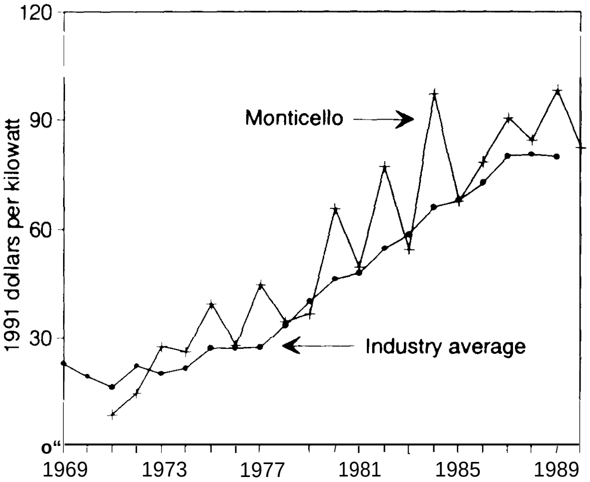
Assessment period	Plant operations	Radiological controls	Maintenance/ surveillance	Emergency preparedness	Engineering Security	technical support	Safety assessment/quality verification
3/89-6/90.	1	2	1	1	2	2	1
12187-2189, ...	1	1	1	1	3	2	2

Assessment period	Plant operations	Radiological controls	Maintenance	Surveillance	Fire protection	Emergency preparedness	Security	Outages	Quality programs and administrative controls effecting quality	Licensing activities	Training and qualification effectiveness
6/86-1 1187.	2	1	1	1	1	1	2	1	2	1	2
12184- 5186.	1	1	1	2	1	1	1	1	2	1	2
7/83-11/84.	1	2	1	2	2	1	1	1	2	1	N
7/82-6-83.	2	2	2	1	2	1	1	1	N	2	N
7/81-6183.	1	2	2	1	2	1	1	1	N	1	N
7/80-6181.	1	2	1	1	2	2	2	1	N	N	N
10/79-9/80.	2	3	2	2	2	3	2	2	2	N	2

NOTE: Category 1 indicates superior performance, where reduced NRC attention maybe appropriate; Category 2 indicates good performance anda recommendation to maintain normal NRC attention; Category 3 indicates acceptable performance, where NRC may consider increased inspections, and Category N indicates insufficient information to support an assessment. As these categories suggest, the NRC SALP rankings include no failing grades.

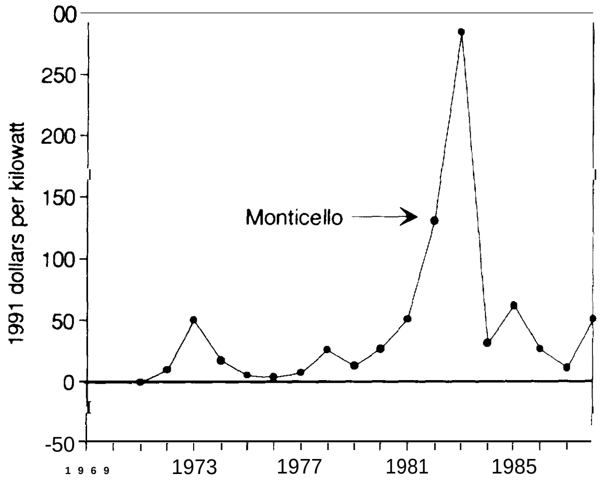
SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants; Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Figure 5-4--Monticello Non-Fuel Operation and Maintenance Costs (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Figure H-Monticello Capital Additions (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

To renew Monticello's license, NSP will have to build a dry cask storage facility. However, the State of Minnesota requires a "certificate of need' before storage of spent fuel at the plant site can be increased. NSP requested and received a certificate of need to install the high-density spent fuel storage racks in 1978 but has not yet requested certification for the dry cask storage facility. This application will be a milestone in the license renewal process.

Decommissioning

NSP owns a 100 percent, undivided interest in Monticello. In a 1990 decommissioning report submitted to the NRC, NSP indicated a Monticello decommissioning trust fired target value of $119 million (1986 dollars) .[14] Initial annual deposits into an external trust fund were projected at $11.4 million. In subsequent correspondence, NSP stated that the Minnesota Public Utilities Commission denied their request for a rate increase to collect these monies. Later, in 1991, the utility was permitted to start recovering the estimated decommissioning costs.

To evaluate decommissioning costs in more detail, NSP commissioned TLG Engineering, Inc. (TLG) to develop a site-specific estimate. Only the DECON alternative was evaluated. This study estimated decommissioning costs of $277.4 million (1990 dollars). The current collections for decommissioning total $30 million: $9.7 million in internal funds, $17 million in an external, tax-qualified fund, and $3.6 million in an external, nonqualified fund. There has been no evaluation of the potential impact on decommissioning of premature retirement or license renewal at Monticello.

[14] Northern States Power CO., "Monticello Nuclear Generating Plant Amendment to Financial Assurance for Decommissioning," letter dated Sept. 6, 1990.

Table 5-13-Salem Construction and Licensing History

	Date of construction permit	Construction cost (year of expenditure, In millions)	Operating license start date	Commercial operation	License expiration	Lifetime Capacity factor
Unit 1.	September 1968	$661.6	December 1976	June 1977	August 2016	58 percent
Unit 2.	September 1968	$614.3	May 1981	October 1981	April 2020	59 percent

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Deeommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

SALEM CASE STUDY[15]

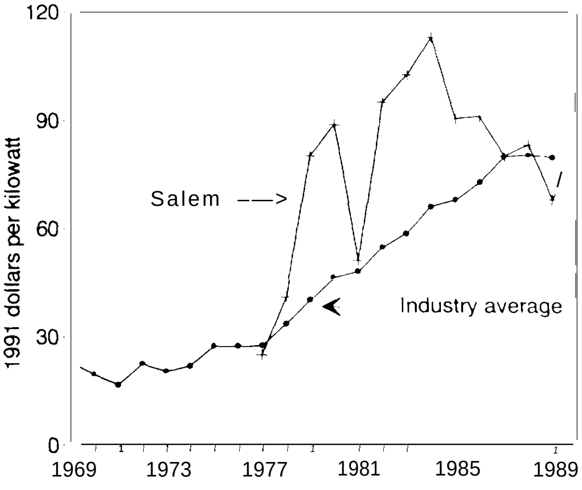
Performance and Operating History

The two units at Salem have four owners: Public Service Electric and Gas Co. (PSE&G), Philadelphia Electric (PE), Atlantic City Electric (ACE), and Delmarva Power and Light (DP&L).[16] Both units are 1,106-MWe Westinghouse PWRs and operated by PSE&G. The license terms for both units reflect recovery of the time spent during construction. The application for this extension was made to the NRC in August 1987 and was approved in June 1991, resulting in the recovery of almost 20 reactor-years of operating time (total for both units). A summary of the construction and licensing history for Salem is listed in table 5-13.

In the early 1980s, Salem experienced several operational difficulties that caused higher than average operating costs (figure 5-6). Capital additions costs have been average, though costs were higher in the early 1980s, partly in response to TMI-mandated backfits (figure 5-7). As indicated by critical operating time, Salem availability has been highly variable, but on average similar to the rest of the industry. Other NRC performance indicators are summarized in table 5-14.

In 1983, a steam generator level transient at Salem resulted in reactor shutdown. An analysis of the sequence of events (leading up to and following the rapid insertion of the reactor control rods into the core) revealed that critical breakers in the automatic shutdown circuits had failed to operate. If the operators had not manually activated the circuit breakers, the event could have caused significant plant damage. PSE&G was

Figure 5-6--Salem Non-Fuel Operation and Maintenance Costs (1991 dollars per kilowatt)

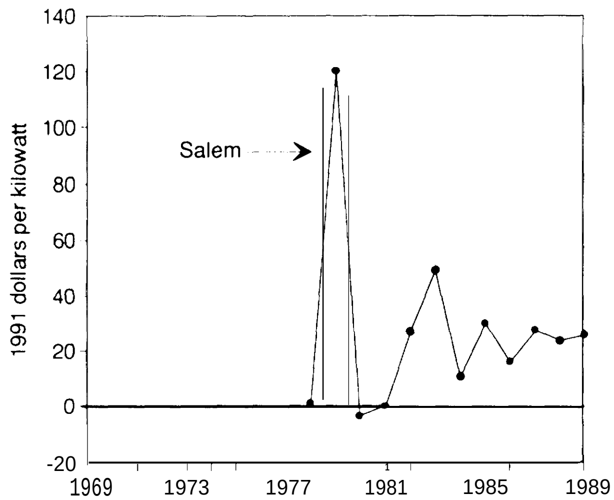


SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

[15] Unless noted otherwise, all information in the discussion of this plant is from personal communication between Public Service Electric and Gas Co, (PSE&G; James Bailey et al.), ABZ, Inc. (Edward Abbott and Nick Capik), and the Office of Technology Assessment (Robin Roy and Andrew Moyad) on, and subsequent to, June 1, 1992.

[16] PSE&G and PE each own 42.59 percent, and ACE and DP&L each own 7.41 percent.

Figure 5-7—Salem Capital Additions (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

freed a then-record $850,000.[17] The NRC also conducted a full scale investigation of the event, which included almost every aspect of PSE&G's management at Salem. The NRC review led to several significant and costly actions that resulted in above average O&M costs at Salem. Once the actions were completed, O&M costs decreased to levels consistent with the rest of the industry.

The class of event that resulted in the failure of the automatic shutdown system is called an "anticipated transient without scram" (ATWS). In the decade prior to the Salem event, the NRC had been developing a specific ATWS rule to address the potential consequences of such an event. During that time, BWRs were considered to be more susceptible to ATWS than PWRs, and the NRC had required BWR owners to install hardware modifications to make the event less likely and more manageable. After the Salem ATWS occurred, however, the NRC began to require hardware upgrades, as well as reanalysis of the likelihood of such events at PWRs.

In the late 1980s, the NRC noted several problems at Salem, including periods of inadequate supervision, deficiencies in maintenance and surveillance, and high numbers of personnel errors. Over the past 10 years, Salem has submitted 995 LERs, averaging 46 per year at Unit 1 and 53 per year at Unit 2. This rate is 30 percent higher than the industry average. PSE&G claims that this larger than average number is due to the reporting philosophy at Salem, where events are reported that may not be at other facilities. In the last 5 years, the NRC judged three LERs as significant. These three are summarized in table 5-15. Salem received two additional NRC fines: a $50,000 fine in March 1988 for fire protection violations and a $50,000 fine in April 1989 for violations involving environmental qualification of electrical equipment.

In November 1991, the main turbine and generator at Unit 2 sustained severe damage when the turbine failed to trip during testing.[18] An NRC investigation stated the accident was ''preventable.' More than a year before the failure, PSE&G found similar equipment for the Unit 1 turbine inoperative due to mechanical binding. Although PSE&G stated that the matching equipment in Unit 2 would be replaced during its next outage, no replacement was made. Subsequent investigation identified that the Unit 2 equipment was immobilized by foreign debris, rust, and corrosion. Including the costs of replacement power, repairs cost approximately $76 million. The root cause of this failure was identified as the lack of preventive maintenance, surveillance testing, and procedural compliance.[19]

A summary of SALP scores for Salem is provided in table 5-16. While these scores reflect the problems of 1983 and 1989, they do not

17 *Nucleonics Week*, vol. 33, No. 31, July 30, 1992.

18 *Nucleonics Week*, vol. 33, No. 31, July 30, 1992.

19 *Inside NRC*, vol. 13, No. 22, Nov. 4, 1991.

Table 5-14—Performance Indicators for Salem

	1985	1986	1987	1988	1989	1990	1991
Total scrams	10	18	5	9	6	5	2
Scrams > 15% per 1,000 hours	0.86	1.41	0.27	0.89	0.84	1.39	0.22
Scrams < 15% per 1,000 hours	0.13	0.5	0.13	0	0.13	0	0
Safety system actuations	2	3	0	1	4	5	2
Significant events	1	6	3	1	1	0	1
Safety system failures	0	6	13	8	5	8	9
Forced outage rates	15.83	15.25	4.623	12.5	16.5	24.5	9.25
Equipment forced out per 1,000 hours	1.44	2.19	0.50	2.01	1.73	2.78	0.41
Critical hours	11,450	12,726	12,836	12,930	13,926	11,405	13,897

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

appear to anticipate the 1991 turbine accident. In fact, the category for operations actually improved in 1990.

Staffing. See Hope Creek, above.

Life Attainment and License Renewal

PSE&G has initiated several programs to monitor and improve the material condition of SSCs during the current and any renewed license terms:

- *Revitalization: This 5-year* program is aimed at upgrading systems and components to increase their productivity and reliability and to reduce long-term costs. No budget has been established, and the net impact on cost and performance is yet to be determined.
- *Configuration Baseline Documentation Project:* Part of the motivation behind this project was a 52 day plant shutdown at Salem that resulted from incomplete design information. The program covers 54 Salem systems and completion is scheduled in 1996 at a total cost of $14 million (not including any ensuing expenses). PSE&G maintains that this program has improved their understanding of plant design, improved design control and engineering productivity, and provided a better foundation for evaluating design modifications. In addition, PSE&G considers this program a sound foundation for any future considerations of license renewal.
- *Five-Year Life-Cycle Management Program;* Initiated in 1991, this program consists of system reviews to identify age-related degradation of SSCs. In 1992, four systems were reviewed.

PSE&G has identified no significant issues that would preclude license renewal for the Salem units, although the utility has not performed a full assessment of the NRC requirements. At present, no additional NRC inspections or audits are

Table 5-15-Summary of Significant Events at Salem

Unit	Date	Description
Unit 1	12/09/87	Procedural and testing inadequacies in the reactor protection and control systems.
Unit 1	5120/89	Loss of RHR due to inadvertent discharge of the nitrogen accumulator.
Unit 2	1 1/09/91	Severe damage due to a turbine overspeed, which occurred from the failure of the emergency trip and overspeed protection solenoid valves (SOVs). The SOVs failed due to mechanical binding caused by foreign material, sludge, rust, and corrosion.

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Table 5-16-Summary of Salem SALP scores

Assessment period	Plant operations	Radiological controls	Maintenance/ surveillance	Emergency preparedness	Engineering Security	technical support	Safety assessment/quality verification
8/90-12/91	2	2	2	1	1	2	2
5/89-7/90.	2	2	2	1	1	2	2
1/88-4/89.	3	2	2	2	1	2	2

Assessment period	Plant operations	Radiological controls	Maintenance	Surveillance	Fire protection	Emergency preparedness	Security	Outages	Quality programs and administrative controls effecting quality	Licensing activities	Training and qualification effectiveness
10/86-12/87.	2	2	1	2	N	1	1	1	1	2	2
10/85-9/86.	2	1	1	2	N	1	1	2	2	2	2
9/84-9/85.	2	1	2	2	2	2	1	2	N	2	N
10/83-8/84.	3	2	2	2	3	2	1	2	N	2	N
10/82-9183.	3	2	2	2	2	1	2	1	N	2	N
9181 -8182	2	1	1	1	2	2	3	1	N	2	N
7/80-6/81.	1	2	1	1	2	2	3	1	1	N	N

NOTE: Category 1 indicates superior performance, where reduced NRC attention may be appropriate; Category 2 indicates good performance and a recommendation to maintain normal NRC attention; Category 3 indicates acceptable performance, where NRC may consider increased inspections, and Category N indicates insufficient information to support an assessment, As these categories suggest, the NRC SALP rankings include no failing grades.

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants; Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

anticipated other than those standard for the industry.

Spent Fuel Storage

The Salem operating licenses expire August 2016 (Unit 1) and April 2021 (Unit 2). The Unit 1 spent fuel pool has sufficient temporary storage space until 1998, assuming no loss in operational full core reserve (a requirement imposed by the NRC for continued operation). Unit 2 has adequate space until 2002, also assuming no loss in operational full core reserve. Although no plans have been made for additional temporary storage space, adequate space is available on the site if new facilities (i.e., dry storage) become necessary. PSE&G has developed plans to rerack both spent fuel pools, which would permit continued operation (with full core reserve) until 2007 for Unit 1 and 2011 for Unit 2.

Decommissioning

Salem's four joint owners will divide decommissioning costs. In a decommissioning report submitted to the NRC on July 24, 1990, PSE&G estimated its share of the total estimated decommissioning cost at $60.5 million (1990 dollars) per unit. PSE&G deposited this amount in a qualified external sinking fired at the rate of $2.3 million per year for Unit 1 and $2.0 million per year for Unit 2. Under applicable ratemaking orders, decommissioning cost recovery is based on a net negative salvage value of 20 percent. This additional amount is included in PSE&G's rate base and will be added to the trust fund annually; these funds will be treated as a prepayment for future years. In 1989, trust fund balances were $20.2 million (Unit 1) and $14.8 million (Unit 2). Current fund requirements are based on a 1986 TLG study.

In a decommissioning report provided to the NRC on July 26, 1990, PE established its share of the total escalated decommissioning cost at $60.5 million (1990 dollars) per unit, which will be deposited into either a decommissioning escrow account or a qualified external sinking fund at the rate of $2.3 million per year for Unit 1 and $2.0 million per year for Unit 2. PE anticipates that most future payments will accrue in the trust funds, while payments to the escrow accounts would occur only to prevent the total contribution from exceeding the amount permitted by the Internal Revenue Code to retain tax qualification. As of May 1990, the Unit 1 escrow account had a balance of $4 million, and the trust fund had a balance of $7 million. The Unit 2 escrow account had a balance of $2.7 million, and the trust fund had a balance of $6.14 million. PE estimates the value of each trust fund will be $61 million per unit when decommissioning begins.

In a decommissioning report provided to the NRC on July 26, 1990, ACE established its share of the total escalated decommissioning cost at $10.5 million (1990 dollars) per unit. Deposits will accrue in an external sinking fired at the annual rate of $628,235 for Unit 1 and $721,307 for Unit 2. ACE estimates the value of this fund will be $32 million for Unit 1 and $38 million for Unit 2 when decommissioning begins. Estimates of fund growth assume a 2 percent return after taxes and inflation. The ACE funding requirements are based on the 1986 TLG study. Finally, the PSE&G decommissioning report indicates the DP&L funding share is $10.5 million per unit. Annual DP&L deposits into an external sinking fund are $400,000 for Unit 1 and $600,000 for unit 2.

In addition to these decommissioning reports submitted to the NRC, PSE&G commissioned site-specific cost estimates for Salem. The first study was performed by TLG in 1987 and estimated decommissioning costs of approximately $376 million for both units, greatly exceeding the estimates submitted to the NRC. A 1990 update increased the estimates to $450 million for both units. PSE&G maintains that the increase is due to the increased cost of onsite spent fuel storage, increased labor rates, development of more realistic schedules for decommissioning activities, higher charges for low-level waste compaction and disposal, higher energy costs, and higher insurance liability costs. PSE&G estimates also that disposal of radioactive waste will account for 30 percent of the total cost, which may be an underestimate because of uncertainties associated with the availability and costs of future disposal sites. The TLG studies have not been submitted to the NRC but are used for State utility rate proceedings.

PSE&G appears to have conducted no formal evaluation of the impact on decommissioning in case of the premature retirement of either Salem unit. Consistent with license renewal progress, PSE&G has not modified their decommissioning planning or funding to assess the potential of license renewal. Both of these actions are consistent with common industry practice. Finally, as mentioned in the Hope Creek discussion, legislation currently under review in the New Jersey State legislature may affect future decommissioning planning for Salem.

SONGS CASE STUDY[20]

Performance and Operating History

San Onofre is the site of three nuclear power plants operated by Southern California Edison (SCE). The San Onofre Nuclear Generating Station Unit 1 (SONGS 1) began operation in 1968 as a demonstration project cofunded by the Atomic Energy Commission. The unit is a three-loop Westinghouse PWR rated at 436 MWe, although it has operated at less that 380 MWe in recent years due to steam generator problems. SONGS 1 is jointly owned by SCE (80 percent) and San Diego Gas and Electric Co. (SDG&E, 20 percent), SONGS 1 was constructed for $88 million. Since then, modifications totaling $720 million have been made, including seismic qualifications, TMI modifications, fire protection, standby power addition, environmental qualification, a sphere enclosure project, single-failure analysis, security, and the systematic evaluation program.

SONGS Unit 2 is a 1,070-MWe Combustion Engineering PWR built by Bechtel; commercial operation began in August 1983. SONGS Unit 3 is a 1,080-MWe Combustion Engineering PWR built by Bechtel; commercial operation began in April 1984. These two units are owned jointly by SCE (75.05 percent), SDG&E (20 percent), Anaheim Electrical Division (3.16 percent), and Riverside Public Utilities (1.79 percent). There have been no applications yet to recover license time spent during construction of either Unit 2 or Unit 3. A summary of the construction and licensing history of SONGS is listed in table 5-17.

SONGS 1 has experienced prolonged periods of nonoperation, primarily to fix and replace equipment and to modify the facility to comply with Federal regulations. Since the unit began operation, the steam generators have been a particular problem. Each generator consists of approximately 11,000 tubes used to convert water to steam. Of these tubes, over 1,400 (more than 10 percent) have been plugged due to damage and leakage. Such plugging reduces steam generator performance and thus the amount of electricity generated. These problems prompted SCE in 1980 to insert sleeves into more than 6,900 tubes. The sleeves extend tube life and reduce subsequent degradation. No other nuclear plant in the United States has undertaken such a large-scale sleeving program.

In accordance with the Full-Term Operating License (FTOL), which was formally issued in 1991 for SONGS 1, SCE was required to complete several plant modifications prior to Fuel Cycle 12, as directed by a 1990 NRC order. (Before 1991, SONGS 1 had operated on a provisional operating license.) The changes were estimated to cost about $125 million and were

20 Unless noted otherwise, all information in the discussion of this plant is taken from personal communication between Southern California Edison Co. (SCE; Harold Ray, Joseph Wambold et al.), ABZ, Inc. (Edward Abbott and Nick Capik), and the Office of Technology Assessment (Robin Roy and Andrew Moyad) on, and subsequent to, Oct. 14, 1992.

Table 5-17—SONGS Construction and Licensing History

	Date of construction permit	Construction cost (year of expenditure, in millions)	Operating license start date	Commercial operation	License expiration	Lifetime capacity factor
Unit 1.	March 1964	$88.0	March 1967	January 1968	March 2004	53.8 percent
Unit 2.	October 1973	$2,540	August 1982	August 1983	October 2013	72.3 percent
Unit 3.	October 1973	$2,250	September 1983	April1984	October 2013	76.5 percent

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

initiated as required. In parallel, SCE sought CPUC approval for the required expenditures, which the utility determined were cost effective. However, the CPUC Division of Ratepayer Advocates (DRA) opposed approval based on its own economic analyses, which found the plant not to be cost effective. There were several areas of disagreement between DRA and SCE involving such issues as future plant capacity factors, future operating costs, potential steam generator replacements, and SCE forecasts of replacement power costs.[21]

In 1992, SCE, SDG&E, and the CPUC agreed to close the 23-year-old plant, because of the potential problems with cost effectiveness. Operations ceased at the end of Fuel Cycle 11 on November 30, 1992. Under the agreement, SONGS 1 will be operated and staffed as usual until all fuel is removed from the reactor vessel in late 1993. Thereafter, staffing and support requirements will decrease over the next 2 years to levels appropriate for long-term plant storage. The settlement agreement also allows SCE and SDG&E to recover their remaining capital investments over 4 years ($110 million for SDG&E and $350 million for SCE). The previously authorized rate of return applied until Unit 1 was shutdown, and the rate based on long-term debt has applied since shutdown.

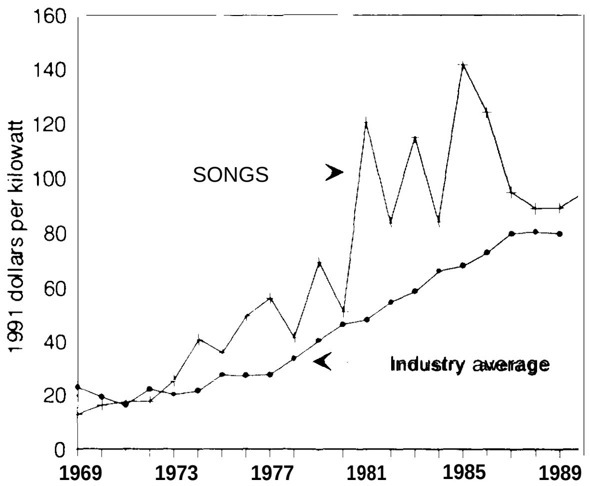
All fuel in the SONGS 1 reactor vessel will be stored in its spent fuel pool. To provide sufficient space for this full core offload, 49 fuel assemblies now in the Unit 1 pool will be transferred to the Units 2 and 3 pools. The SONGS site is licensed for such fuel transfers between pools. Current plans are to restrict all fuel storage to onsite pools, but dry storage facilities may be considered in the future to expand storage capacity. After fuel removal, Unit 1 will remain in a long-term shutdown mode. SCE has identified the systems that will remain operable and those that will not. The operable systems will primarily ensure the safe storage of fuel in the pool.

Overall, SONGS performance is consistent with industry averages. Despite earlier difficulties with Unit 1, final operations continued for 377 days. Total plant O&M costs are slightly higher than average, a result of the higher cost of living and thus higher salaries in southern California (figure 5-8). In addition, costs were higher than normal when Units 2 and 3 frost came on line.

Federal Energy Regulatory Commission (FERC) data on SCE capital additions provide little information. From 1975 through 1983, capital costs were significantly greater than average, reflecting Unit 1 upgrades. Since then, FERC data indicate below average costs for SCE (figure 5-9). Aside from these FERC data, SCE forecasts capital expenditures on a 5-year basis. Projected costs for the next 5 years range from a low of $47 per kilowatt-installed to a high of $62 per

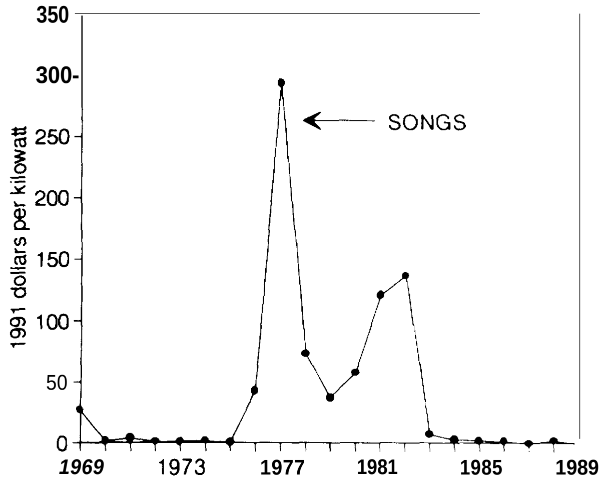
21 Robert M. Kinosian, Regulatory Program Specialist, Division of Ratepayer Advocates, California Public Utilities Commission, memorandum to the Office of Technology Assessment, Feb. 8, 1993,

Figure 5-8-Southern California Edison (SONGS) Non-Fuel Operation and Maintenance Costs (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Figure 5-9--Southern California Edison (SONGS) Capital Additions (1991 dollars per kilowatt)



SOURCE: ABZ, Inc. "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

kilowatt-installed (in year of expenditure dollars). These estimates include overhead costs.[22]

SCE's performance indicators show no distinct weaknesses or noteworthy trends. In response to issues related to design basis documentation, SCE has instituted a comprehensive program to prevent future problems (discussed in the next section). SCE's performance indicators are listed in table 5-18. Events rated as significant by the NRC in the last 5 years are summarized in table 5-19. Compared to other region IV licensees, though, SCE continues to perform well; the utility's SALP scores are listed in table 5-20.

SCE employs a total of 3,500 people for the 3 units, about 2,400 of which are permanent staff. About 2,300 employees are located at the plant site, and the remainder work at headquarters. The site employees are roughly divided as follows: Security (234), Outage Management (36), Maintenance (594), Operations (292), Emergency Preparedness (104), Training (137), Technical (165), Chemistry (65), Health Physics (272), and Site Support (326). According to SCE, staff size peaked when Units 2 and 3 came on line but has been decreasing ever since.

Life Attainment and License Renewal

SCE has two active programs applicable to both life attainment and license renewal: the Current License Basis Program and the Design Bases Documentation and Reconstitution Program. SCE is one of two utilities that has volunteered to participate in an NRC pilot program to develop current licensing bases. The nascent program is first gathering the necessary documentation and investigating methods for future computer retrieval. Anticipated meetings with the NRC will help better define the requirements of the program and develop schedules. SCE

22 Recent correspondence between SCE and CPUC suggests that SCE has raised capital additions cost estimates for SONGS 2 and 3 to about $70 per kilowatt. Robert M. Kinosian, Regulatory Program Specialist, Division of Ratepayer Advocates, California Public Utilities Commission, memorandum to the Office of Technology Assessment, Feb. 8, 1993,

Table 5-1 8—Performance Indicators for SONGS

	1985	1986	1987	1988	1989	1990	1991
Total scrams.	14	14	4	0	3	3	3
Scrams > 15% per 1,000 hours.	0.74	0.56	0.16	0	0.13	0.13	.012
Scrams < 15% per 1,000 hours.	0.17	0.33	0	0	0	0	0
Safety system actuations.	4	1	1	1	2	1	0
Significant events.	2	4	2	4	2	0	0
Safety system failures.	0	2	1	13	9	4	5
Forced outage rates.	6.3	10.2	2	1.9	18.7	2.8	8.5
Equipment forced out per 1,000 hours.	0.53	0.74	0.24	0.08	0.95	0.17	0.29
Critical hours.	4,708	5,624	7,134	6,012	5,687	6,051	6,568

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommission ing, " contractor report prepared for the Off ice of Technology Assessment, February 1993.

expects to complete the development of the licensing basis by June 1993 with a budget of about $400,000.

SCE's San Onofre Design Bases Documentation and Reconstitution program is designed to retrieve, reconstruct, confirm, and document SONGS's nuclear power plant design bases in a series of Design Bases Documents. The SCE Design Bases Documentation (DBD) Program will document the meaningful plant design bases and ensure prompt access to the associated information. The purpose is to record plant design at the time the operating license was issued, as well as any subsequent design modifications. The program will document the original design bases to help compare their consistency with existing design details. SCE operating, maintenance, and engineering staffs will have access to the information.

With the shutdown of SONGS 1, the program applies only to Units 2 and 3. Although the program is not specifically designed to extend the licensing of Units 2 and 3, its completion would ease any effort to extend either plant license. The DBDs will support a variety of engineering, licensing, and plant operations activities. The scope of the DBD Program includes systems considered important to plant safety, systems with safety-related functions, and select nonsafety-related systems. Systems covered in the plant Technical Specifications are also included.

Table 5-1 9-Summary of Significant Events at SONGS

Unit	Date	Description
Unit 1.	1 2/1 2188	195 steam generator tubes may not have been hard rolled, creating the potential for their disconnection from the tube sheet in the event of a steam line break accident.
Unit 1.	12/1 2/88	An electrical design deficiency could cause a non-class 1 E swing bus not to load shed on a diesel generator start with an SI signal present. A single failure could cause loss of a diesel generator, because a diesel would be required to operate above its T/S rating.
Unit 2.	12/1 5188	19 valves in the CCW system may fail during a seismic event, which would render the CCW system inoperable.
Unit 3.	12/1 5/88	19 valves in the CCW system may fail during a seismic event, which would render the CCW system inoperable,
Unit 1.	2/2/89	Fasteners on thermal shield support blocks were found broken. Event date unknown.
Unit 1.	3/2/89	A design deficiency was found in the EDG load sequence logic.

SOURCE: ABZ, Inc., "Case Studies of Nine Operating Nuclear Power Plants: Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

Table 5-20-Summary of SONGS SALP Scores

Assessment period	Plant operations	Radiological controls	Maintenance/ surveillance	Emergency preparedness	Engineering Security	technical support	Safety assessment/quality verification
2/90-7-91, ...	2	1	2	1	1	2	2
10/88-1/90.	2	1	1	1	1	2	2
10187-9188.	1	1	2	1	1	3	3

Assessment period	Plant operations	Radiological controls	Maintenance	Surveillance	Fire protection	Emergency preparedness	Security	Outages	Quality programs and administrative controls effecting quality	Licensing activities	Training and qualification effectiveness
6/66-9/87.	1	2	2	2	2	1	2	1	2	2	1
10184-5/86.	2	1	2	2	1	2	2	1	2	2	2
6/83-9/84.	3	3	2	2	2	1	2	2	N	2	N
7181-5/83.	2	2	2	2	2	1	2	1	2	2	N
6/80-6/81.	2	3	3	1	2	1	3	1	2	N	N

NOTE: Category 1 indicates superior performance, where reduced NRC attention maybe appropriate; Category 2 indicates good performance and a recommendation to maintain normal NRC attention; Category 3 indicates acceptable performance, where NRC may consider increased inspections, and Category N indicates insufficient information to support an assessment. As these categories suggest, the NRC SALP rankings include no failing grades.

SOURCE: ABZ, inc., "Case Studies of Nine Operating Nuclear Power Plants; Life Attainment, License Renewal and Decommissioning," contractor report prepared for the Office of Technology Assessment, February 1993.

In general, the contents of self-contained documents are not duplicated in the DBD. Rather, these documents are incorporated by reference, when applicable. Examples of self-contained documents include:

- ASME Code Stress Reports.
- Equipment Qualification Data Packages.
- Vendor Manuals.
- Operations and Maintenance Procedures.
- Industry Codes and Standards.
- Specifications.
- Design Changes, Calculations.
- Design Detail Drawings.

Select DBDs are validated through a process intended to provide reasonable assurance the DBD is complete, accurate, and consistent with the existing as-designed, as-licensed, as-built, as-operated, as-maintained configuration of the plant. The scope of the validation process is flexible and may vary from selective sampling to comprehensive review of the information, depending on system factors such as importance to safety, history of past problems, complexity, and size.

The process of DBD program validation may include any of the following: walkdowns performed by the DBD Engineer (DBD preparer) during document preparation; supervisory review during DBD preparation stages, which may include evaluation by an Independent Review Engineer (IRE); and an interdisciplinary review performed by technicians from Nuclear Engineering, Nuclear Licensing, Station Technical, and other sections of the nuclear staff independent of the DBD Section. DBD managers will select the method of validation on a case-by-case basis.

Decommissioning

SONGS Unit 1 is jointly owned by SCE (80 percent undivided interest) and SDG&E (20 percent undivided interest). In a decommissioning report submitted to the NRC on July 24, 1990, SCE calculated its share of the Unit 1 decommissioning costs at $69.5 million (1986 dollars). This amount was determined in accordance with the formula for minimum financial assurance in 10 CFR 50.75. The California PUC has authorized SCE to collect $190 million (1992 dollars) for decommissioning costs based on a site-specific cost estimate.

Because SONGS is located on Federal land, SCE is required to return the site to its original condition (’‘beach sand’ after operation. Therefore, the decommissioning cost estimate is greater than the NRC mandated minimum (which considers radiological decommissioning only). Decommissioning funds are being deposited into an external trust account (currently $18 million per year). To date, SCE has collected $175 million. No changes to the estimated decommissioning costs have been made since the decision to shutdown Unit 1 early.

In a decommissioning report submitted to the NRC on July 24, 1990, SDG&E calculated its share of the Unit 1 decommissioning costs at $17.4 million (1986 dollars). This amount was determined in accordance with the formula in 10 CFR 50.75. As required, SDG&E deposits are made annually into an external trust.

Under current plans, SONGS 1 will be decommissioned by the SAFSTOR method. The shutdown and long-term storage of Unit 1 is planned as four phases. The frost phase consisted primarily of preparation for final shutdown and has already been completed. The second phase consists of performing a normal plant shutdown at the end of the current refueling cycle and the removal of the fuel from the reactor vessel to the spent fuel pool. The third phase will prepare the unit for long-term storage until Units 2 and 3 are decommissioned. The fourth phase is decommissioning the unit in accordance with an NRC reviewed and approved decommissioning plan.

Phase 1: Preparation for Plant Closure

This phase includes the preparation and submittal of license amendments, detailed plans for disposition of SSCs, review and evaluation of station programs and procedures, and development of plans to reduce regulatory requirements to reflect the unit's defueled condition. These plans were discussed during meetings with the NRC. Information from other prematurely shutdown plants were gathered and analyzed with respect to the unique situation at SONGS 1.

Phase 2: Shutdown and Plant Closure

The unit was shut down in the second phase. The shutdown occurred on November 30,1992, at the end of fuel cycle 11. The generator output breakers will be opened and the reactor coolant system will be cooled down to permit disassembly of the reactor vessel. Concurrent with vessel disassembly, 49 fuel assemblies from Unit 1 will be moved to the spent fuel pools at Units 2 and 3 to allow the removal of the cycle 11 core. When this fuel offload is completed, the reactor vessel internals will be reinstalled in the vessel. The vessel head will be placed back on the vessel but not tensioned.

SSCs needed to store the fuel safely will continue to operate in accordance with applicable Technical Specifications. Other important operable systems include radiation monitoring, the emergency diesel generators, radwaste processing, and the fuel handling equipment. The SSCs not required to contain radioactive material will be secured to prevent long-term degradation and the inadvertent spread of contamination. Uncontaminated systems will be secured to minimize occupational hazards. The detailed plans to accomplish these long-term storage activities are in preparation,

Following shutdown, measures will be taken to reduce personnel radiation exposure and ease access to areas that may require monitoring. These measures will include wearing lead blankets for shielding in hot spots and some decontamination. In addition, stored radioactive material such as spent resins and falters will be disposed. If practicable, decontamination by system flushing to reduce general radiation will also occur.

Storage plans include periodic monitoring to ensure contaminated SSCs are not degrading. Current plans outline an aggressive program to reduce the need for active storage and monitoring equipment. Ideally, all fuel in the Unit 1 spent fuel pool will move to Units 2 and 3 to eliminate the maintenance of equipment and systems needed to cool and store fuel. In the interim, any SSCs not required for spent fuel storage will be drained, vented, and de-energized. The reactor coolant system will be drained and vented. Some water will remain at low points in the circulating loops and in the reactor vessel but will evaporate with time. The steam generators, residual heat removal pumps, heat exchangers, pressurizer relief tank, and the excess letdown and regenerative heat exchanger will also be drained and vented. The containment sump will be pumped dry.

Electric motors in the containment will be de-energized; remaining oil will be removed to reduce the fire hazard. All remaining fluid supplies to the containment will be isolated and any remaining equipment such as lights secured. The containment vent will be locked open to provide a vent path to the plant stack. The equipment and personnel hatches will be locked and posted. Cathodic protection and periodic inspections necessary to maintain the sphere, which contains the radioactive material, will continue until Units 2 and 3 are decommissioned.

Equipment associated with the turbine generator will be secured. The condenser hotwell will be drained. The feed and condensate systems including the condensate storage tank will be drained and vented enough to prevent accidental flooding. All drains and vents will remain open. All electric motors will be secured by tagging their associated breakers. The generator will be purged of hydrogen and vented. The hydrogen tanks and backup nitrogen bottles will be returned to the vendor. The turbine lube oil system will be drained and cleaned. The lube oil reservoir will be emptied, wiped down, and vented. Any motors containing oil will be drained. Salvageable equipment (e.g., the turbine generator) may be preserved until a purchaser is found.

Equipment in the reactor auxiliary building needed to maintain boron concentration in the core will be secured. The work includes draining and flushing the piping and pumps in the chemical volume control system, such as the boric acid injection pump and the boric acid tank. The radioactive material in the solid and liquid radwaste systems will be processed, packaged, and either stored onsite or sent to a burial site. The solid and liquid radwaste systems will remain in service during deactivation of potentially radioactive systems. This will permit processing of waste generated when systems are drained. The fuel pool cooling and clean up system will be the last one vented and drained. The solid and liquid radwaste systems, therefore, will probably remain in service for at least 3 or 4 years.

Once all potentially radioactive material has been processed, the solid, liquid, and gaseous radwaste systems will be secured. To reduce the potential for airborne contamination, preventive measures will be taken, such as decontaminating floors, walls, and equipment surfaces. Final radiation surveys of the rooms will be performed and the rooms will be posted. All accesses to the building will be locked and posted. Routine building inspections will be performed, with the frequency depending on ALARA (as low as reasonably achievable) radiation exposure concerns and the anticipated degradation of the equipment.

Once the fuel is transferred to Units 2 and 3, the remaining operable systems will be secured. The component cooling and salt water cooling systems will be drained and vented. The electrical and air supplies will be positively isolated. The spent fuel pool cooling and cleanup systems will also be drained and vented. The water remaining in the pool will be pumped out and processed and the pool will be covered. The fuel handling equipment and associated support systems will be secured. The fuel storage building will be surveyed and posted. All accesses will be locked and posted. Routine inspections will be performed consistent with ALARA and any anticipated degradation.

The labs, offices, and equipment shops in the main building will be maintained as needed to support work during plant storage. Some of the facilities may support work for Units 2 and 3. As a result, the HVAC systems will be maintained for habitability, and lighting, fire protection, water, and sewage systems will be maintained too. Access to the control room, switchgear, and cable spreading rooms will be limited to employees supporting the remaining active systems, such as lighting.

Once the fuel has been removed from Unit 1, round the clock coverage for the plant will probably not be needed. The control room will be secured by de-energizing the control and lighting panels and then locked. Similarly, the cable spreading and switchgear rooms will be deactivated and locked. The diesel generators will be preserved to the extent needed to maintain their commercial value. The fuel oil tanks and associated piping will be drained. Any energized support systems such as starting air and control panels will be secured. The diesel generator rooms will be locked. Finally, ventilation systems for areas containing radioactive material, such as the containment and the reactor auxiliary building, will be aligned to provide a single vent path through the Unit 1 stack. The ventilation system and the stack monitor will remain in service until the unit is decommissioned.

Phase 3: SAFSTOR

Current plans call for the long-term storage of Unit 1 until Units 2 and 3 are decommissioned. As noted above, routine inspections will be performed consistent with ALARA goals and the anticipated degradation of Unit 1 SSCs. A small staff will perform such inspections routinely and provide maintenance. In addition, this staff will maintain any records required to support eventual decommissioning, including descriptions of the secured state of the plant such as marked-up drawings, radiation surveys, and records of any spills.

Phase 4: Final Site Decommissioning

Under current plans, fourth phase will begin when Units 2 and 3 are decommissioned. As required by NRC decommissioning rules, a Unit 1 decommissioning plan will be submitted within 2 years after plant shutdown; the plan will be updated as needed while Units 2 and 3 remain operating. Given the lengthy storage period (in excess of 20 years), advancements in decommissioning technologies such as decontamination methods and waste volume reduction are likely. As a result, changes to the Unit 1 plan are anticipated. In addition, the decommissioning options for Units 2 and 3 should be consistent with Unit 1 and provide the same level of site restoration.

Units 2 and 3 are owned by SCE (75.05 percent undivided interest), SDG&E (20 percent undivided interest), the City of Anaheim (3.16 percent undivided interest), and the City of Riverside (1.79 percent undivided interest). All four of these owners have provided for decommissioning financial assurance according to the formula in 10 CFR 50.75; all four have established separate external trust funds to collect these monies. Their respective funding shares to decommission units 2 and 3 were outlined in separate reports submitted to the NRC in July 1990 and are the following (1986 dollars): $78.6 million per unit (SCE), $21 million per unit (SDG&E), $3.3 million per unit (City of Anaheim), and $1.9 million (City of Riverside). In sum, these shares amount to almost $105 million (1986 dollars) per unit.

The California PUC has authorized SCE to collect $620 million (1992 dollars) for decommissioning costs (based on a site-specific cost estimate). As mentioned earlier, SCE is required to return the site to ‘‘beach sand” condition after operation, because the SONGS units are on Federal land. Therefore, the decommissioning cost estimate is significantly greater than the NRC-mandated minimum, which considers reactor-block decommissioning only. SCE is currently depositing $18 million per year into its external trust. To date, the utility has collected $375 million. No revision of the estimated decommissioning cost has been made since the decision to shutdown Unit 1, and no formal evaluation has been performed to evaluate the decommissioning potential impacts on from either premature retirement or license renewal of Units 2 and 3.