Southern California Edison

Application No. ______________

Exhibit No. (SCE-3)

Witness ______________

SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

SONGS 1 COST-EFFECTIVENESS ANALYSIS

Before the

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rosemead, California
July 1991

SOUTHERN CALIFORNIA EDISON COMPANY

SONGS 1 COST-EFFECTIVENESS ANALYSIS

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CHAPTER 1

SONGS 1 OPERATION POLICY

I

RECOMMENDATION

San Onofre Nuclear Generating Station Unit No. 1 (SONGS 1 or Unit) is nearing the end of a prolonged period during which it has been progressively modified to meet requirements which changed significantly since it entered service in 1968. The remaining modifications have been identified by the Nuclear Regulatory Commission (NRC), in connection with issuance of the Full Term Operating License (FTOL) for the Unit, and are planned for completion during the next refueling outage, prior to operation in Fuel Cycle 12.

The estimated cost of these modifications and other capital expenditures is $125 million, and initial work amounting currently to about $20 million has been performed. Most additional work has been suspended, pending determination of the cost-effectiveness of continued operation in this proceeding.

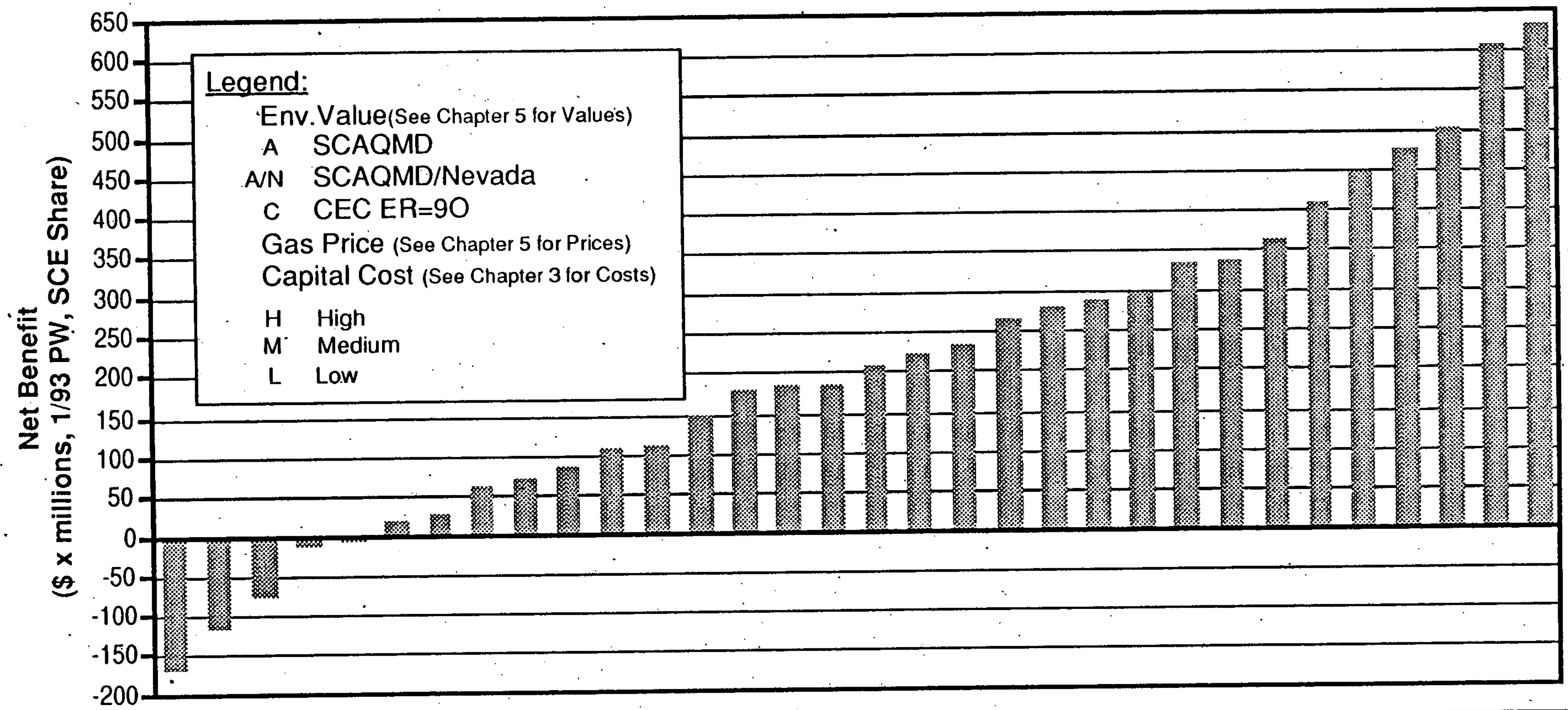
Southern California Edison Company (Edison or Company) has evaluated the cost-effectiveness of continued operation, using sensitivities which span a range of possible future values for important variables. (The possibility that the SONGS 1 steam generators will need to be replaced at some future time has also been considered.) Cost-effectiveness is significantly affected by these variables, especially the value applied to residual air emissions established by the California Public Utilities Commission (Commission). 1/

Continued operation of SONGS 1 will make a significant contribution to reduction of residual air emissions. This is an important benefit of making the additional investment required to operate beyond the current fuel cycle. In addition, SONGS 1 contributes to Edison's resource diversity goals by using nuclear fuel which is forecast to be a stable, low-cost fuel well into the future.

As summarized in Figure 1 and discussed in detail in Chapter 5, continued operation of SONGS 1 is cost-effective under most scenarios examined. Edison therefore requests Commission authorization for the Fuel Cycle 12 capital expenditures as soon as possible. Prompt resumption of Fuel Cycle 12 work will minimize the delay in commencement of Fuel Cycle 12, and will increase the benefit of continued operation. Also, continued operation of SONGS 1 will maintain the opportunity to seek NRC authorization at a later time for extension of its operating license beyond March 2007.

1/ SDG&E will provide its cost-effectiveness evaluation separately.

SONGS UNIT 1
COST-EFFECTIVENESS SENSITIVITIES



Case	6	12	18	4	24	30	5	N/A	10	2	16	11	17	N/A	8	3	22	14	28	23	1	29	9	15	20	26	7	13	21	27	19	25
Env. Value	A/N	A/N	A/N	A/N	A/N	A/N	A	A	A/N	A/N	A/N	A	A	C	A/N	A	A/N	A/N	A/N	A	A	A	A	A	A/N	A/N	A	A	A	A	A	A
Gas Price	L	L	L	M	L	L	L	H	M	H	M	L	L	H	H	M	M	H	M	L	H	L	M	M	H	H	H	H	M	M	H	H
Capital Cost	H	H	M	H	M	L	H	M	H	H	M	H	M	M	H	H	M	M	L	M	H	L	H	M	M	L	H	M	M	L	M	L
% Cap. Factor	60	70	70	60	80	80	60	44	70	60	70	70	70	70	70	60	80	70	80	80	60	80	70	70	80	80	70	70	80	80	80	80

BRPU Case

Reference Case

FIGURE-1

II

INTRODUCTION

SONGS 1 is one of three electrical generating units at the San Onofre Nuclear Generating Station (SONGS), located on the coast about four miles south of San Clemente, California. The site was established under Federal Law in 1964 on a portion of the Camp Pendleton military reservation. Its use under that law is limited to generation of electricity using nuclear energy.

SONGS 1 was designed, constructed, and began operation in 1967 as a jointly sponsored government-industry "demonstration project" for the generation of electricity on a commercial scale, using nuclear energy. The nuclear reactor is a Westinghouse Pressurized Water Reactor (PWR), and the Unit has a rated net electrical output of 436 megawatts (MW).

Consistent with regulatory practice at the time, the Atomic Energy Commission (AEC) issued a Provisional Operating License (POL) for SONGS 1 in March 1967. Following a period of testing, the Unit entered commercial operation January 1, 1968. Edison and San Diego Gas & Electric Company (SDG&E) initially applied to the AEC for a FTOL in 1970. The FTOL is to replace the POL and will provide for operation to March 2007, which is 40 years following initial issuance of an operating license.

As described in Chapter 2, 2/ the NRC 3/ is now expected to issue the FTOL by the end of 1991. Also, as discussed in Chapter 2, an NRC Order dated January 2, 1990 (January 2, 1990 Order) identified requirements for issuance of the SONGS 1 FTOL. The January 2, 1990 Order identified those actions that were required to be completed before operation in Fuel Cycle 11, 4/ with the balance required to be completed prior to operation in Fuel Cycle 12. Fuel Cycle 11 began on June 30, 1990 and is expected to be completed in the Fourth Quarter of 1992.

The FTOL will be issued effective to 2004, pursuant to Edison and SDG&E's initial application to the AEC in 1970. Subsequently, as described in Chapter 2, the FTOL will be extended to March 2007 in accordance with the administrative procedures issued by the NRC subsequent to Edison and SDG&E's initial application. Accordingly, operation to March 2007 has been included in this cost-effectiveness evaluation. 5/

As discussed below, SONGS 1 is nearing completion of a period of extensive modifications that significantly reduced its capacity factor throughout the decade of the 1980s. Following completion of the remaining FTOL modifications

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2/ See Section II.B.3 of Chapter 2.
3/ The NRC was created and assumed the regulatory responsibilities of the AEC in 1974.
4/ The period of time from the beginning of a refueling outage (an outage to replace fuel in the reactor) through unit operation to the beginning of the subsequent refueling outage is called a fuel cycle.
5/ Exhibit No. (SCE-18)______, SONGS 1 post-Cycle 11 Capital Additions, submitted in Edison's 1992 GRC included operation through 2004.

prior to Fuel Cycle 12 operation, SONGS 1 operation will no longer be limited by the requirement to perform extensive upgrade modifications, as has occurred from 1980 through 1993. A total of 79 Westinghouse PWRs similar in design to SONGS 1 are currently in service worldwide, 50 of them in the United States. Therefore, a large data base exists for evaluating SONGS 1 operation and for forecasting its future performance.

Edison owns 80 percent of SONGS 1; SDG&E owns the remaining 20 percent. Edison is the operator of SONGS 1. This exhibit addresses the costs of the post-Fuel Cycle 11 modifications and other actions needed to meet the requirements of the January 2, 1990 Order and other expenditures determined by Edison to be necessary on a total cost basis (100 percent of costs) in Chapters 3 and 4. A range of allowances has been included for Fuel Cycles following Fuel Cycle 12 to provide for unidentified future capital requirements in the cost-effectiveness evaluation. SONGS 1 benefits are evaluated for Edison's share of the Unit in Chapter 5 and these benefits are then compared to Edison's share of costs. Sensitivities were quantified for the following input parameters in the cost-effectiveness evaluation: gas prices, value for residual emissions, capacity factor, and capital costs.

III

ACTIONS REQUIRED FOR FTOL ISSUANCE

The requirements for FTOL issuance result in substantial capital expenditures for Fuel Cycle 12.

Capital expenditures for initial engineering and other studies, and to develop necessary estimates to support this filing and continuing NRC submittals, began in early 1990. The cost of this preliminary work and required long lead-time systems and material purchases is currently approximately $20 million. 6/

As can be seen from the results of the various scenarios presented in Chapter 5 of this exhibit, the extent of cost-effectiveness for continued operation of SONGS 1 is heavily dependent on which assumptions the Commission determines should be used in the analysis. Under this circumstance, Edison believes it is prudent to defer most of the remaining Fuel Cycle 12 capital expenditures until the cost-effectiveness of continued SONGS 1 operation has been addressed in the BRPU proceeding. Therefore, the start of Fuel Cycle 12 operation is assumed to be delayed until January 1994, due to this deferral of required Fuel Cycle 12 capital expenditures. The current Fuel Cycle 11 operation is forecast to be completed in late 1992. 7/

In addition to the Fuel Cycle 12 modifications required to complete the remaining FTOL actions in accordance with the January 2, 1990 Order, the evaluation of cost-effectiveness includes all other capital expenditures

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6/ See Chapter 3, Capital Requirements.

7/ A forecast schedule for future operation is shown in Table 3-B, Chapter 3, Capital Requirements.

during Fuel Cycle 12 and a range of allowances for subsequent fuel cycles. The basis for the capital expenditures allowance for fuel cycles after Fuel cycle 12 is a study of the experience of both SONGS 1 and other similar Westinghouse PWRs in a SONGS 1 peer group selected for comparison purposes (all of which have received their FTOLs). As described in Sections V and VI below, the range of capital expenditures represents the cost against which the benefits of post-Fuel Cycle 11 operation 8/ can be compared to evaluate the cost-effectiveness of such operation.

IV

OPERATION THROUGH THE END OF FUEL CYCLE 11

SONGS 1 is currently operating in Fuel Cycle 11. Operation from the beginning of plant life through the end of this fuel cycle consists of two distinct periods, which are described next.

A. Operation From 1968 Through 1979

During its first twelve years of operation (1968-1979), SONGS 1 accumulated a lifetime capacity factor of 73 percent, even though significant modifications were completed during the period. These modifications included enclosure of the steel reactor containment building in a surrounding reinforced concrete shield and the addition, with electrical interconnection, of two large standby diesel generators for emergency use if all offsite power is lost.

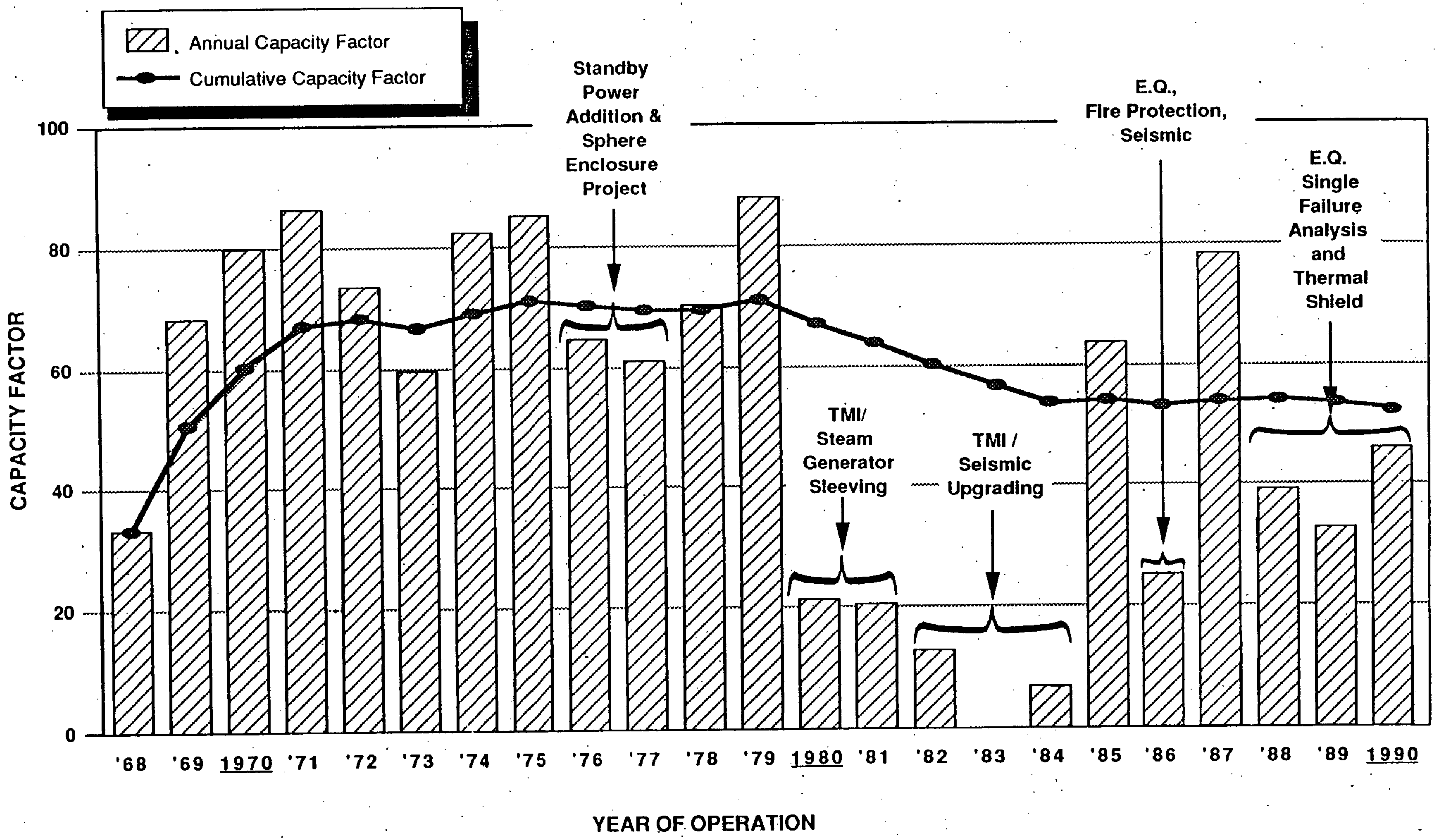
Operation of the Unit has been similar to other Westinghouse PWRs when extended outages for NRC-required modifications were not imposed.

B. Operation From 1980 Through 1992

Figure 2 shows that, for the past eleven years of operation, the SONGS 1 capacity factor has been about half what it was during the first twelve years. This change results primarily from lengthy planned outages to perform modifications and does not reflect any significant change in Unit reliability when it is in operation. In the absence of the modifications which were performed in parallel, capacity factor would also have been reduced on two occasions during the period by equipment performance unrelated to NRC-required modifications. During 1980-1981, sleeving of many steam generator tubes was performed, and more recently during Fuel Cycles 10 and 11 refueling outages, thermal shield supports within the reactor vessel required inspection and replacement. Notwithstanding these two equipment-related problems, the capacity factor would have remained at about 70 percent if extended outages had not been imposed to perform NRC-required modifications.

8/ "Post-Fuel Cycle 11 operation" begins with Fuel Cycle 12 operation and ends in 2007.

SONGS UNIT 1 CAPACITY FACTORS



1-6

FIGURE-2

SONGS 1 operational reliability remains reasonably consistent from 1968 to the present, as shown by the cycle-by-cycle production factors. 9/ Production factors for Fuel Cycles 1 through 10 are shown in Table 1-A below:

Table 1-A

SONGS 1 Complete Fuel Cycle Production Factors

Fuel Cycle	Production Factor	Fuel Cycle	Production Factor
1	63%	6	82%
2	88%	7	87%
3	90%	8	70%
4	75%	9	86%
5	91%	10	74%

The reasons for the modifications which have adversely affected the SONGS 1 capacity factor, and the bases for forecasting the level of post-Fuel Cycle 11 modifications, are discussed below.

V

MODIFICATIONS REQUIRED FOR FTOL ISSUANCE AND SUBSEQUENT OPERATION

Continued operation of any nuclear facility requires the licensee to undertake all actions required by the NRC. Many of these involve modifications impacting both cost and electricity production; others are engineering studies which impact only cost. The following discussion provides an overview of the modifications required for issuance of the SONGS 1 FTOL and subsequent operation.

Required SONGS 1 modifications including system replacements can be categorized according to the following four reasons:

1. To comply with changes in NRC requirements unique to the San Onofre site, primarily those related to seismic criteria.

2. To comply with changes in NRC requirements unique to SONGS 1, primarily as a result of its "demonstration plant" origin.

3. To comply with changes in NRC requirements generic to the nuclear industry. 10/

4. To maintain the reliability of SONGS 1 operation, for example, replacement of worn or obsolete systems.

9/ The production factor is the capacity factor between planned outages.
10/ As a result of the accident of Three-Mile Island (TMI) in 1979, the number of these changes increased dramatically during the early 1980s.

As discussed in Chapter 2, modifications for each of the first two reasons has an origin, a beginning in time, and an end point when the NRC requirements will have been satisfied. In general, the modifications due to Reasons 1 and 2 above will be completely satisfied as required for issuance of the FTOL. After FTOL issuance, modifications due to Reasons 3 and 4 will continue at a reduced level consistent with that required for peer Westinghouse PWRs. Once the NRC requirements in the January 2, 1990 Order have been satisfied, SONGS 1 will again be able to operate without extended outages for large numbers of modifications due to changes in NRC requirements as it did during the period 1968-1979, before most of the NRC requirements changes occurred. Its performance should be consistent with other, similar nuclear units which have also satisfied such changes.

As discussed earlier, the January 2, 1990 Order identified modifications and other actions required for FTOL issuance. Certain of these modifications and other actions were completed prior to Fuel Cycle 11 operation, with the balance to be completed prior to Fuel Cycle 12 operation. Subsection A, below, discusses modifications and other actions which either have been or will be completed through the end of Fuel Cycle 11, including those actions identified in the January 2, 1990 Order. Subsection B, below, describes modifications and other actions to be undertaken during the Fuel Cycle 12 refueling outage, including those required by the January 2, 1990 Order. Subsection C, below, describes the reasons for the delay of substantial Fuel Cycle 12 expenditures pending a Commission decision on the cost-effectiveness of SONGS 1 continued operation. Finally, Subsection D explains why the SONGS 1 capital expenditures are non-deferrable.

A. Modifications Through the End of Fuel Cycle 11

A significant number of modifications and other actions have been required to permit operation of SONGS 1 beginning in 1968 through the end of Fuel Cycle 11 in 1992. These modifications include the Fuel Cycles 9-11 Integrated Implementation Schedule (IIS) modifications for which the Commission established a $201 million (1986 $) cost cap in D.85-12-024. 11/ These modifications and other actions have satisfied the changes in NRC requirements applicable to Fuel Cycle 11 operation for Reasons 1 through 3, above. These Reasons 1 through 3, as well as Reason 4, are discussed below:

1. Changes in NRC Requirements Unique to the San Onofre Site

Revised earthquake criteria for the San Onofre site significantly increased seismic design forces for SONGS 1. During 1982-1986, modifications were made throughout the plant and to the protective seawall to strengthen structures and equipment.

11/ D.85-12-024 [mimeo], dated December 4, 1985, in A.85-05-008, authorized Edison and SDG&E to perform SONGS 1 IIS modifications during Fuel Cycles 9-11, with a cost cap of $201 million (1986 $).

Establishment of the San Onofre State Beach in 1971 required construction of a reinforced concrete building surrounding the original SONGS 1 steel reactor containment building. This work was completed in 1977.

No further modifications are anticipated due to changes in NRC requirements unique to the San Onofre site.

2. <u>Changes in NRC Requirements Unique to SONGS 1</u>

The design, construction, and initial operation of SONGS 1 as a "demonstration plant" were the bases for development of many criteria subsequently applied in the licensing of commercial PWRs built after SONGS 1. As a result, modifications had to be backfitted to SONGS 1 to comply with new AEC/NRC requirements. The NRC established the "Systematic Evaluation Program" to manage these changes.

For example, SONGS 1 operated until 1976 under a criterion that assumed it would not simultaneously experience a reactor accident and complete loss of offsite power supply. The coincident occurrence of such unrelated events has a very remote probability. However, design criteria established for plants following SONGS 1 include such an occurrence. Large standby emergency diesel generators were accordingly added to SONGS 1 in 1977.

Changes of this kind have continued, including modifications to electrical distribution systems during the Fuel Cycle 11 refueling outage to provide for added redundancy. Several of the Fuel Cycle 12 modifications required for FTOL issuance and post-Fuel Cycle 11 operation are in this category. Their estimated costs are included in Chapter 3.

3. <u>Changes in NRC Requirements Generic to the Industry</u>

Most of the changes in this category are the result of lessons learned from the TMI accident. As required for plants throughout the United States, most of the resulting modifications for SONGS 1 are now completed. Remaining items are addressed in the January 2, 1990 Order.

In addition to TMI requirements, major changes in generic NRC requirements have also occurred in areas such as Fire Protection criteria and Environmental Qualification of Safety Equipment. Currently identified items of this kind, which remain to be completed, are specified in the January 2, 1990 Order. Their costs are reflected in the capital estimates for the Fuel Cycle 12 refueling outage.

Changes in generic NRC requirements are expected to continue at a reduced level. This assumption is reflected in the range of allowances for capital expenditures during Fuel Cycles 13-18, included in the evaluation of SONGS 1 cost-effectiveness.

4. Changes to Maintain the Reliability of SONGS 1 Operation

Modifications including the replacement of major systems are occasionally made in order to maintain plant reliability. For example, instrumentation systems that have become unreliable, and for which spare parts are no longer available, have been replaced by systems of current design.

As with items in Category 3, 12/ allowances for capital expenditures in this category during Fuel Cycles 13-18 operation have been included in the sensitivities assessed in the Chapter 5 cost-effectiveness evaluation. The allowances for future capital expenditures assume continued operation using the existing steam generators and provide for replacement of other equipment or systems, as may be required to maintain reliable operation.

B. Modifications Prior to Fuel Cycle 12 Operation

Modifications and other actions required for FTOL issuance must be completed by the end of the Fuel Cycle 12 refueling outage in accordance with the January 2, 1990 Order. As discussed in Chapter 3, the estimated cost of these modifications and other capital expenditures before post-Fuel Cycle 11 operation is $125 million. Initial engineering and other studies required to evaluate and estimate this work commenced in 1990. The cost of this initial work and required long lead-time systems and material purchases is currently approximately $20 million and is included within the estimated $125 million.

As indicated in the January 2, 1990 Order, these modifications and other actions complete the work required for issuance of the SONGS 1 FTOL by the NRC.

C. Delay of Substantial Fuel Cycle 12 Capital Expenditures

Substantial additional Fuel Cycle 12 capital expenditures, beyond the $20 million discussed above, were initially scheduled during 1991 and early 1992 to support completion of modifications during the refueling outage commencing late in 1992. This schedule was based on consideration of the capital expenditures by the Commission in Edison's 1992 GRC.

With the transfer of consideration from the GRC to the Biennial Resource Plan Update (BRPU), 13/ most of this work has been suspended, pending the results from that proceeding. The effect of this suspension will be a delay in the commencement of Fuel Cycle 12 operation. A delay from February 1993, the date for commencement of Fuel Cycle 12 assumed in Exhibit No. (SCE-18)______, to the 1992 GRC Application, until January 1994 has been included in this cost-effectiveness evaluation.

12/ See Section V.A.3 above.
13/ I.89-07-004

D. Non-Deferrability of SONGS 1 Capital Expenditures

SONGS 1 is an existing operating generating facility and is included in the CEC's ER-90 Resource Plan. The capital expenditures for SONGS 1 included in this application do not involve extending the life of SONGS 1, nor do they involve an expansion to the Unit. 14/

Over 80 percent of the capital expenditures planned for Fuel Cycle 12 are required by the NRC prior to Fuel Cycle 12 operation. These expenditures are not energy-related capital costs. Any delay in the implementation of the Fuel Cycle 12 capital expenditures will delay the start of post-Fuel Cycle 11 operation and will decrease operational benefits and increase costs as discussed below:

- o Delay of the start of post-Fuel Cycle 11 operation will shorten the remaining useful life of SONGS 1 because NRC operating licenses are issued with a specific end date. Therefore, SONGS 1 would simply have fewer months/years to operate with a corresponding reduction in operational benefits for the system.

- o During the period that plant operation was deferred, the continuing O&M costs pending restart would be significant. 15/

- o Operating personnel trained for SONGS 1 would have to be kept on the payroll for the duration of any deferral, otherwise the difficult and expensive task of acquiring and training new, qualified personnel to operate SONGS 1 would be necessary.

Therefore, SONGS 1 operation cannot reasonably be deferred and it should be considered a non-deferrable resource. Consequently, it is inappropriate to perform the ICEM "first-year test," as discussed in Chapter 5.

14/ The HP Turbine Modification planned for Fuel Cycle 13 (as described in Chapter 3) will enable the unit to routinely operate at a net capacity of 405 MW which is below its historical rated net capacity of 436 MW as included in the CEC ER-90 Resource Plan. The unit currently operates at approximately 380 MW to minimize further corrosion of the steam generator tubes. This modification will be implemented to improve the cost-effectiveness of the existing resource, but will effectively derate the Unit from 436 MW to about 405 MW.

15/ O&M expenses for a temporary shutdown of SONGS 1 would be at least as high as the O&M expenses for permanent shutdown which in the first year are estimated to be 85 percent of O&M expenses when the unit operates. For further information on the O&M expenses of permanent shutdown, see Section IV of Chapter 4.

VI

MODIFICATIONS DURING POST-FUEL CYCLE 12 OPERATION

As indicated above, the cost-effectiveness evaluation allows for additional, undefined modifications in Fuel Cycle 13 and beyond, due to Reasons 3 (Changes to NRC Requirements Generic to the Industry) and 4 (Changes to Maintain Reliable Operation) described in Section V above. Table 1-B shows the range of allowances used for these undefined modifications and other capital expenditures beyond Fuel Cycle 12:

Table 1-B

Range of Allowances for Post-Fuel Cycle 12 Capital Expenditures
($ in Millions, 100% Share)

Fuel Cycle	Low	Medium	High
13 *	50	60	70
14	50	60	70
15	40	50	60
16	30	40	50
17	20	30	40
18	20	30	40

* The allowances for Fuel Cycle 13 include $15 million for modification to the High Pressure Turbine, as described in Chapter 3.

This range of allowances for future capital expenditures is consistent with SONGS 1 peer units already issued FTOLs after completing their post-TMI and other generic modifications, as discussed in Chapter 3. Also, as discussed in Chapter 2, Edison's experience with current NRC procedures demonstrates that additional new requirements affecting SONGS 1 will be limited compared with earlier experience, especially during the decade following the TMI accident. Assuming continued operation with the existing steam generators, the amounts shown in Table 1-B are considered to represent the range of likely future capital requirements. Consideration has also been given to the cost-effectiveness of steam generator replacement as an alternative to continued operation using the existing components. Thus far, 12 PWRs worldwide (9 in the U.S.) have had their steam generators replaced. Approximately 20 others in the U.S. are in various stages of planning and preparation for steam generator replacement. The SONGS 1 steam generators might be replaced for either of two reasons, as follows:

1. Although the sleeving of many tubes in 1980-1981 has permitted the original steam generators to remain in service for the past ten years, the normal maximum output from the Unit has been reduced by about 50 MWe. This has been taken into account in this evaluation of cost-effectiveness of continued operation. However, unanticipated future deterioration of the existing steam generators could further reduce Unit output and make steam generator replacement necessary for continued cost-effective operation.

Based on extrapolation of performance over the past 10 years since sleeving was performed, replacement should not be required for continued operation through March 2007. In the event that accelerated degradation were to occur in the future, steam generator replacement would not be anticipated prior to Fuel Cycle 15 in 1999. Therefore, replacement at that time has been included in the scenarios considered, as discussed in Chapter 5.

2. Edison has no current plans to extend the life of SONGS 1 and this application does not request that the Commission authorize Edison to make capital expenditures to extend the life of the Unit. However, the NRC is currently establishing the requirements for issuance of 20-year renewals to existing operating licenses. If renewal of the SONGS 1 license is sought from the NRC, then replacement of the steam generators and recovery of the original 50 MWe would likely be performed. If license renewal is not sought, and replacement of the steam generators is not undertaken, then the steam turbine will be modified to recover about 25 MWe of output for Fuel Cycles 13 and beyond. It is anticipated that a decision regarding a 20-year license renewal and related plans for steam generator replacement will be made prior to Fuel Cycle 13. The added cost of potential steam generator replacement is discussed in Chapter 3, Section III.B.4.

VII

POST-FUEL CYCLE 11 OPERATION

A. Comparison With 1968-1979 SONGS 1 Operation

Following completion of the Fuel Cycle 12 outage and the actions required for FTOL issuance, SONGS 1 should achieve an average capacity factor of 70 percent for the period of 1994-2007, which compares to 73 percent achieved during the 1968-1979 period. Performance at the 70 percent level is consistent with both the assumption of continuing modifications at the levels discussed in Section VI above, as well as the activity levels actually experienced during the 1968-1979 period. Performance at this level does not depend on higher production factors than those achieved throughout the 1968-1990 period. 16/

However, operation at capacity factors of 60 percent and 80 percent over the period are possible and have also been evaluated. The lower value could result from the need for increased steam generator maintenance, and the higher value reflects the upper range of current performance by peer units.

Achievement of a 70 percent capacity factor during the post-Fuel Cycle 11 period is based on completion of the actions required for FTOL

16/ As discussed in Section IV.B above.

issuance in the January 2, 1990 Order such that subsequent modifications are required at a level comparable to other Westinghouse PWRs.

B. Comparison to Peer Group Plants

To evaluate post-FTOL, post-Fuel Cycle 11 operation of SONGS 1 in terms of industry experience, Edison has studied the operation and performance of a peer group of seven Westinghouse PWRs located at five sites. These units, their year of initial operation and their lifetime capacity factors are shown in Table 1-C.

Table 1-C

Performance of SONGS 1 Peer Group Units

Plant Name	Units	Initial Operation	Lifetime Capacity Factor (%)
Connecticut Yankee	1	1968	71
Ginna	1	1970	73
Point Beach	2	1970	77
Prairie Island	2	1973	82
Kewaunee	1	1974	82

The performance of these similar Westinghouse PWRs demonstrates that a 70 percent capacity factor for SONGS 1 during the post-Fuel Cycle 11 operating period is reasonable. Performance better than 70 percent can also be expected.

The capacity factors for an even larger data base of PWRs are shown in Table 1-D.

Table 1-D

Industry Capacity Factor Assessment 17/

Data Base: All U.S. Westinghouse PWRs
Time Frame: Most Recent Three-Year Average

Capacity Factor	Number of Plants
<60%	6
60%-70%	8
70%-80%	12
>80%	12

Note: This table excludes six units that were on the NRC "Troubled Plants" list during this three-year period due to various management problems.

17/ Source: World Nuclear Performance, May 1991.

This assessment covers a 3-year period for which data are available. The SONGS 1 evaluation of cost-effectiveness covers a period of 14 years, and it is expected that action would be taken in response to short-term operation below a 60 percent capacity factor to restore long-term performance to a 60 percent value, or higher. Similarly, although operation might exceed 80 percent over a short term, this value is taken as a reasonable upper bound on long-term performance.

C. Post-Fuel Cycle 11 O&M and Fuel Expenses

Chapter 4 addresses the incremental operation and maintenance (O&M) expenses and fuel expenses projected for SONGS 1 in the cost-effectiveness evaluation of post-Fuel Cycle 11 operation. Incremental expenses are those costs exceeding the costs for long-term shutdown, pending decommissioning of the San Onofre site. 18/ These incremental costs include the costs associated with the uranium fuel cycle, including both the mining and related activities and the disposal of the waste streams.

VIII

COST-EFFECTIVENESS OF POST-FUEL CYCLE 11 OPERATION

The modifications required to support operation following Fuel Cycle 11 through March 2007 are discussed in Sections V.B and VI above. These modifications include those required by the January 2, 1990 Order. All capital expenditures required for post-Fuel Cycle 11 operation are described in Chapter 3. Post-Fuel Cycle 11 operating expenses are discussed in Chapter 4, as noted in Section VII.C above.

As discussed previously, based on its initial operation, its production factor, and comparison with peer group units, SONGS 1 should achieve an average capacity factor of 70 percent following the Fuel Cycle 12 refueling outage. However, average capacity factors over the 14-year period of 60 percent and 80 percent are also possible and have been included in this evaluation. 19/

A. Cost-Effectiveness of Post-Fuel Cycle 11 Operation Using Various Alternative Sensitivities

The benefits of SONGS 1 operation include substantial values associated with its avoidance of residual air emissions, as discussed in Chapter 5. Including these values, its cost-effectiveness ranges from a net

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18/ Decommissioning of SONGS 1 is planned on the basis that it would occur concurrently with the planned decommissioning of SONGS 2 and 3 in 2013.

19/ In accordance with requirements in the BRPU, a capacity factor of 44 percent has also been included, representing the past five-year average for SONGS 1 and covering a portion of the period when substantial modifications have been made to the Unit.

benefit, expressed in 1993 dollars, of a positive $632 million to a negative $166 million, depending on the assumed values for:

1. Average capacity factor over the period in the range of 60 percent to 80 percent.

2. Capital expenditure requirements.

3. Natural gas prices.

4. Residual air emission values.

Edison has evaluated SONGS 1 cost-effectiveness over this broad range in order to ensure an adequate basis for Commission decision. In particular, the value of residual air emission costs must be determined by the Commission as a critical element of the overall SONGS 1 cost-effectiveness.

The results are summarized in Figure 1 and discussed in detail in Chapter 5.

B. <u>Effect of Potential Steam Generator Replacement on Cost-Effectiveness</u>

As discussed in Section VI, many PWRs have either replaced their original steam generators, or are planning to do so. The SONGS 1 steam generators underwent a major repair program in 1980 through 1981, and the Unit has operated at reduced power since then in order to minimize further corrosion of the steam generator tubes and avoid the need for replacement. However, replacement might be needed in the future if:

1. The operating license period were to be extended, since the restoration to full power operation and reduction of maintenance costs would make this cost-effective.

2. Accelerated degradation and resulting power reduction were to make continued maintenance not cost-effective.

As discussed in Chapter 5, the net impact of steam generator replacement in 1999 on a scenario involving the middle values of capacity factor, capital expenditure, gas prices, and residual air emission benefits would be to revise the net benefit from a positive $109 million to a negative $18 million. Therefore even in the event the steam generators were to be replaced, and operation of the Unit not be extended beyond March 2007, only a relatively small net negative impact would result when assuming middle values of the sensitivity variables.

CHAPTER 2

NUCLEAR REGULATORY COMMISSION REQUIREMENTS

I

INTRODUCTION

SONGS 1 operated with little impact on performance from additional Nuclear Regulatory Commission (NRC) 1/ requirements, until shortly after the accident at Three-Mile Island (TMI). After TMI, the following three sources of NRC requirements substantially impacted SONGS 1 performance:

1. Changes in NRC Requirements Unique to the San Onofre Site

   These changes resulted from the imposition of new, higher seismic criteria on the San Onofre site during the licensing of SONGS 2 and 3.

2. Changes in NRC Requirements Unique to SONGS 1

   The NRC evaluated SONGS 1 against current regulatory criteria in a program called the "Systematic Evaluation Program" (SEP). The SEP was established to evaluate older plants, including SONGS 1, against current regulatory criteria to reconfirm and document their safety; and

3. Changes in NRC Requirements Generic to the Industry

   The TMI accident resulted in over one hundred new NRC regulatory requirements for SONGS 1.

Following a lengthy period of modifications and other actions in response to NRC requirements, the few remaining items requiring resolution in connection with issuance of the SONGS 1 Full-Term Operating License (FTOL) were documented in an NRC Order dated January 2, 1990 (January 2, 1990 Order). 2/ These items included all remaining work from the aforementioned three sources, as well as other work. 3/ Completion of this work on a specified schedule is a requirement of the January 2, 1990 Order. After receipt of the FTOL (which is now expected in late 1991) and completion of the remaining January 2, 1990 Order requirements, SONGS 1 will be the same as any other nuclear power plant from a regulatory perspective. In the future, SONGS 1 should experience the same level of modifications as other nuclear power plants, due to any further changes in NRC requirements.

1/ Prior to 1974, the NRC was called the Atomic Energy Commission (AEC). For convenience, the agency is called the NRC throughout this document.
2/ The January 2, 1990 Order is attached as Appendix A.
3/ All items to be completed as a requirement of the January 2, 1990 Order are listed in Appendix B.

II

SONGS 1 REGULATORY HISTORY

The regulatory history of SONGS 1 can be conveniently separated into three time periods:

1. From commercial operation in 1968 until the TMI accident in 1979;

2. From 1980 through the end of Fuel Cycle 12 refueling outage in December 1993, when all plant modifications required by the January 2, 1990 Order for Fuel Cycle 12 operation will be completed; and

3. From 1994 to the anticipated expiration of the Operating License in 2007.

The specific modifications implemented in response to NRC requirements are usually determined through a process in which the licensee responds to the requirements with proposals specific to its unit. These proposals may be accepted in whole, or in part, and generally may be modified in content and schedule in their final, approved form.

The performance of SONGS 1 during these three time periods is discussed in the following sections:

A. Operation From 1968 Through 1979

SONGS 1 was designed and built in the mid-1960s as part of a government/industry "demonstration project" to confirm the expected economy of scale for large commercial nuclear power plants. 4/

During the 12-year period from 1968 through 1979, changing NRC regulations required some modifications to SONGS 1. These modifications were accommodated with little impact on performance. Among the larger plant modifications completed during this period were: (1) the addition of two large emergency diesel generators in response to the NRC requirement that a postulated plant accident must be assumed to occur coincident with a loss of all off-site power; and (2) as a result of allowing public access to the newly created state park at San Onofre Beach, a concrete enclosure surrounding the containment sphere of SONGS 1 was added to reduce radiation exposure to the beach in the event of postulated accidents. Public access to the beach had been restricted before the state park at San Onofre Beach was established.

1. The Provisional Operating License

When SONGS 1 received its operating license, the licensing process involved two steps: (a) issuance of a Provisional Operating

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4/ At that time, a 400 MW nuclear power plant was considered large.

License (POL); and (b) after initial operation and fulfillment of certain regulatory requirements, the issuance of an FTOL. 5/

At the time of SONGS 1 initial operation, relatively few NRC requirements existed due to the lack of operating experience with large commercial nuclear power plants. In fact, the operating experience of the early plants including SONGS 1 formed the basis for later NRC requirements.

2. Changing Requirements for Full-Term Operating License

In the early 1970s (after commercial operation of SONGS 1), many new NRC requirements were established. These requirements evolved from the three previously mentioned new sources, as well as others. These new requirements became a major consideration in issuing the FTOL. Eventually, resolution of these issues became associated with issuance of the FTOL. The resolution of these requirements had a substantial impact on SONGS 1 performance throughout the 1980s.

B. Operation From 1980 Through 1993

During the 1980s, several hundred NRC requirements 6/ were issued in response to the three sources of NRC requirements described previously. These NRC requirements resulted in modifications, studies, procedure changes, and changes in plant programs.

The initiation and resolution of these new sources of NRC requirements are described below.

1. Modifications Resulting From Changes in NRC Requirements Unique to the San Onofre Site: Seismic Issues

During licensing of SONGS 2 and 3, the earthquake criterion for the San Onofre site was revised upward to a ground acceleration value of 0.67g, a one-third increase in seismic design for SONGS 1. To meet the new seismic criterion, Edison undertook a multi-phase effort to reanalyze and modify SONGS 1. The initial phases of analysis and modification were completed in the mid-1970s. The final phase, involving strengthening of structures and equipment, was undertaken from 1982 to 1986. In its July 11, 1986 letter, the NRC acknowledged completion of these seismic modifications: 7/

> All of the [seismic] modifications are now completed.
>
> Based on the [NRC] staff's review of the licensee's long-term service seismic re-evaluation plan, and the

5/ Section II.C.3 discusses the license duration and recapture of the construction interval.

6/ These NRC requirements were either unique to the San Onofre site, unique to SONGS 1, or generic to the nuclear industry.

7/ The July 11, 1986 letter is attached as Appendix C.

> detailed audits of its implementation, the staff concludes the [seismic] program has been properly implemented . . . .

2. Modifications Resulting From Changes in NRC Requirements Unique to SONGS 1: Systematic Evaluation Program (SEP)

Many plant modifications, studies, and other actions were performed during the 1980s as a result of the SEP initiated in 1977. The purpose of the SEP was to review the designs of older operating nuclear power plants to confirm and document their safety compatibility with modern requirements. Eleven plants, including SONGS 1, were included in this review. The SEP process evaluated the "as-built" design against current regulatory requirements in 137 different areas defined as "topics." Upon completion of their evaluation of each of these topics, the NRC either accepted the plant design without change or identified additional analysis, procedure changes, or modifications necessary to bring the plant into compliance with current NRC requirements.

Ultimately, the NRC determined that 48 of the 137 SEP topics either did not apply to SONGS 1 or were being reviewed concurrently in other NRC programs (such as TMI). For 53 of the topics, the NRC determined that SONGS 1 met current criteria or was otherwise acceptable. Review of the remaining 36 topics identified certain aspects of the SONGS 1 design that differed from current criteria. The NRC required additional efforts for these topics. Of these 36 topics, 8/ 26 have been resolved by completion of actions prior to and during the Fuel Cycle 11 refueling outage.

The remaining 10 topics are being resolved during Fuel Cycle 12. One of these topics, although scheduled for resolution during the Fuel Cycle 12 refueling outage, may require additional action if modifications are required. This topic concerns potential modifications to mitigate the effect of pipe breaks in high pressure and temperature water systems on other pieces of equipment important to plant safety. Edison will analyze this topic during Fuel Cycle 12 to determine what, if any, modifications are necessary.

3. Modifications Resulting From Changes in NRC Requirements Generic to the Industry: TMI Accident

After the TMI accident in 1979, the NRC investigation into the causes of the accident resulted in issuance of the "TMI Action Items (NUREG 0737)." The TMI Action Items proposed that a large number of remedial actions be implemented by the nuclear industry to incorporate the lessons learned from TMI. The TMI Action Items included plant modifications such as addition of a third pump to provide feedwater to the steam generators in emergency conditions,

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8/ Appendix D describes each of the 36 SEP topics applicable to SONGS 1, together with their resolution.

changes to the emergency operating procedures, and engineering evaluations of safety system performance during postulated accidents.

The TMI Action Items were given "issue numbers" by the NRC. Of the 148 TMI issues, 37 were determined by the NRC to be inapplicable to SONGS 1. Edison was required to address the remaining 111 issues and most of these have been completed as documented in Edison's letter to the NRC of April 18, 1989. 9/ Of the remaining TMI issues, all but four were resolved during the just-completed Fuel Cycle 11 refueling. These four will be resolved during the Fuel Cycle 12 refueling outage, as documented in the January 2, 1990 Order. Thus, after the Fuel Cycle 12 refueling outage, all TMI requirements will have been completed. 10/

Although not all NRC-required modifications to SONGS 1 evolved from these three sources from 1980 through 1993, the seismic, SEP, and TMI requirements accounted for approximately 70 percent of the work required for regulatory reasons. As previously discussed, all of the SONGS 1 seismic work has been completed. In addition, most of the SEP (also known as the Integrated Plant Safety Assessment) and TMI Action Items have been resolved. Those remaining will be completed during the Fuel Cycle 12 refueling, as required by the January 2, 1990 Order. The January 2, 1990 Order provides a general description of the remaining work:

> These actions [those scheduled by the Order] consist of Three-Mile Island Action Plan items, NRC generic letter items, and action items resulting from the Integrated Plant Safety Assessment for San Onofre Unit 1 (NUREG-0829). Collectively, these actions are referred to as the Full Term Operating License (FTOL) open items 11/

Once an FTOL is issued (expected in late 1991) and the balance of the modifications required by the January 2, 1990 Order are completed in the Fuel Cycle 12 refueling, the three sources of regulatory requirements which combined to produce over a decade of major modifications to SONGS 1 will have been completed.

C. Operation From 1994 Through 2007

After SONGS 1 obtains the FTOL and the balance of the modifications required by the January 2, 1990 Order are completed in the Fuel Cycle 12 refueling, further plant modifications due to revised NRC requirements will occur at only a moderate rate, similar to all other nuclear plants.

9/ The April 18, 1989 letter is attached as Appendix E.

10/ Appendix F provides a brief description of the TMI issues and their resolution for SONGS 1.

11/ A listing of the January 2, 1990 Order open items and the implementation schedule is contained in Appendix B.

1. Future Changes in NRC Requirements Generic to the Nuclear Industry: Generic Safety Issues

New NRC safety requirements are best forecasted by reviewing safety issues currently under NRC evaluation. Generic industry safety concerns are identified either by the NRC staff, the Advisory Committee on Reactor Safeguards, 12/ representatives from the nuclear industry, or the general public. Once identified, the NRC determines the relative safety significance of the issue and, if appropriate, identifies it as a Generic Safety Issue (GSI). The process typically required to resolve a GSI involves significant time for review, along with interaction between the NRC and other organizations, before potential new regulatory requirements may be issued.

After a new GSI has been identified and ranked by the NRC, the agency develops a plan to resolve the issue. This may involve research or completion of analytic studies. When the NRC staff determines that a viable solution to a GSI exists, it publishes the approved method in various NRC documents such as Regulatory Guides, Generic Letters, the Standard Review Plan, Rules, or Orders. Compliance with the solution does not always require modifications to the plant or changes in its operation. Nevertheless, plant operators must demonstrate compliance with the new requirement.

Once identified, a GSI may be classified as an Unresolved Safety Issue (USI) if it is:

> . . . a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed [by the NRC] and that involves conditions not likely to be acceptable over the lifetime of the plants affected. 13/

USIs have high safety significance and most often result in changes to current NRC regulatory requirements or new regulations.

a. Steam Generator Overfill

One typical example of a USI is a postulated failure of the feedwater control system resulting in overfill of the steam generator causing water to enter the steam lines. Steam lines are not designed to carry this added weight during a seismic event. Therefore, if an overfill and earthquake were to occur simultaneously, a steam line could break causing an accident.

This USI was first identified in 1981. It was not resolved by the NRC until the NRC's issuance of Generic Letter 89-19 in

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12/ The Advisory Committee on Reactor Safeguards is an independent safety advisory group reporting to the NRC.

13/ NUREG-0933, "A Prioritization of Generic Safety Issues."

1989. Generic Letter 89-19 required plants to stop feedwater flow when the steam generator water level is high. Edison is demonstrating compliance with this new requirement through a design change to be made in Fuel Cycle 12, presently forecast for late 1992.

No new USIs have been identified in over seven years. To date, all outstanding USIs have been resolved by the NRC. Thus, no USIs are currently open which may result in unforeseen NRC requirements.

2. Future Plant Modifications

To determine the potential for new NRC regulatory requirements which could result in future plant modifications, Edison conducted a review of the 31 open GSIs. Although GSIs are less likely than USIs to require substantial plant modifications, some GSIs may require such modifications. 14/ Edison's review concluded that 17 of the open GSIs would most likely result in potential changes to procedures or technical specifications. Four open GSIs would likely result in potential minor modifications to plant components and equipment. Three open GSIs are not applicable to SONGS 1 since they involve nuclear plant designs or equipment not installed at SONGS 1. Only the remaining seven open GSIs have the potential for even moderate plant modification.

In addition to reviewing open GSIs, Edison reviewed the trend of GSIs over the last eight years to estimate the likelihood of a large number of new GSIs being identified over the remaining licensed life of SONGS 1. This review reveals a significant declining trend. Figure 1 illustrates the number of open GSIs in each year for the last seven years. As shown, each year some new GSIs are identified and some are resolved. The total number of open GSIs peaked in the mid-1980s and has declined to a relatively small number today. In 1990, only one GSI was identified. None has been identified thus far in 1991.

The decreasing number and limited potential for modifications due to the GSIs results from the significant level of operating experience now accumulated with large commercial nuclear power plants. Because many engineering studies and plant modifications have already been completed, additional improvements to plant safety are not being readily identified.

While Edison cannot precisely predict future GSIs, the recent record indicates a trend toward fewer GSIs. Furthermore, new GSIs should not require major plant modifications, since most recent GSIs focus on operational 15/ rather than design issues.

14/ Appendix G identifies, describes, and estimates the potential impact on SONGS 1 of each open GSI.

15/ The operational issues include such items as conduct of maintenance and fitness for duty.

GENERIC SAFETY ISSUES

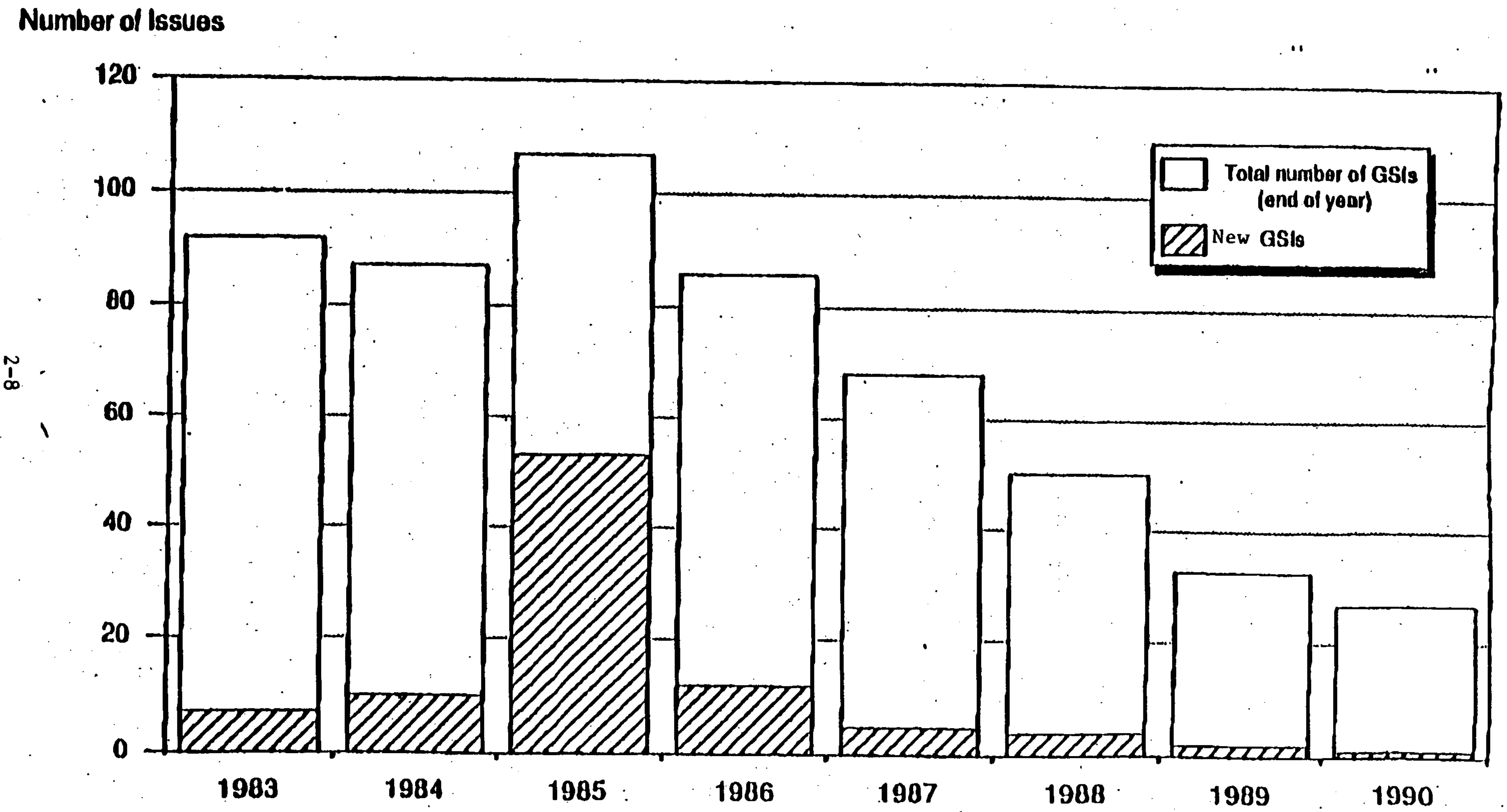

FIGURE 1

3. Operating License Recapture of Construction Period

In the licensing process of a nuclear unit, the NRC, after first reviewing and approving the licensee's application, issues a Construction Permit (CP) allowing construction to commence. After construction and start-up testing has concluded satisfactorily, the NRC issues the Operating License (OL) allowing the unit to commence power operation. (As discussed previously, SONGS 1 was issued a Provisional Operating License (POL).) OLs are typically valid for a period of 40 years. In the early plants, the 40-year OL period started upon issuance of the CP. Starting in 1982 the NRC changed this practice and issued OLs for a period of 40 years starting from the OL date. At this time, the NRC also started granting utilities revisions to existing OLs to resynchronize their existing 40-year OL term to issuance of the OL. This practice is commonly called "construction recapture" 16/.

As of May 1991, the NRC has approved 46 construction recapture requests and denied none. The NRC issued the SONGS 1 CP in 1964 and issued the POL in 1967. Edison applied for the FTOL in 1970 at a time when the 40-year interval began at CP issuance. Consistent with other plants, following issuance of the FTOL Edison will request construction recapture from the NRC, thus providing for FTOL expiration in March 2007.

4. Operating License Renewal

a. Operating License Renewal Regulations

In July 1990, the NRC issued the draft of an OL renewal rule ("Requirements for Renewal of Operating Licenses for Nuclear Power Plants", 10 CFR 54). This proposed rule will specify the requirements for renewal of a plant's OL for up to an additional 20 years. As proposed in the draft rule, the OL renewal process will require an evaluation of age-related issues, an environmental update, and hearings on the OL extension. The final OL renewal rule is scheduled for publication in mid-1991.

Standard Review Plans and Regulatory Guides provide the guidance for implementing and complying with rules. In March 1992, the NRC is scheduled to issue interim drafts of a Standard Review Plan for License Renewal (SRP-LR) and Regulatory Guides concerning the technical requirements, procedures, and standards for implementing 10 CFR 54.

Preceding this, in August 1991 the NRC is scheduled to issue a draft revision to the existing environmental protection rule (10 CFR 51). The proposed revision will address environmental issues to make the OL renewal process more efficient. It will

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16/ An August 18, 1982 memorandum (Appendix H) documents the NRC's regulatory basis for this construction period recapture.

also define the type of NRC staff evaluation needed in reviewing individual OL renewal applications. The final 10 CFR 51 revision is expected to be published in April 1992.

Edison is aware of the proposed rule requirements and the implications for continued operation of SONGS 1. Edison has no current plans to extend the life of SONGS 1 and this application does not presume that the OL will be extended beyond March 2007. Edison expects that OL renewal will be a viable option for SONGS 1 and can be pursued by Edison if appropriate. Edison will evaluate OL renewal for 20 years for SONGS 1 after several years of experience have been gained by other units going through the process.

b. Lead Plant for Operating License Renewal

The Yankee Rowe plant is the lead PWR for OL renewal. This 176 MWe plant is a Westinghouse plant of earlier vintage than SONGS 1. Yankee Rowe is expected to submit its application in September of 1991 for a 20-year renewal of their OL. Edison is closely watching the progress of Yankee Rowe toward obtaining a 20-year renewal of its OL. Edison will factor the Yankee Rowe experience into its own OL renewal planning for SONGS 1.

III

CONCLUSION

SONGS 1 was designed and began operation in the mid-1960s when relatively few NRC requirements existed. The operating experience gained by the larger early commercial nuclear plants, including SONGS 1, resulted in new NRC requirements in the 1970s.

During the 1980s, an increasing number of new NRC requirements were applied to SONGS 1. Resolution of SEP topics, modifying the plant to a higher seismic standard and resolution of TMI Action Items significantly impacted the plant's performance. All SONGS 1 seismic modifications have been completed. The SEP topics and TMI Action Items will be completed as required by the January 2, 1990 Order during the Fuel Cycle 12 refueling. Once the FTOL is issued and the Fuel Cycle 12 modifications are completed, SONGS 1 will, from a regulatory perspective, be the same as any other nuclear plant.

The nuclear industry currently has over 1,400 years of cumulative commercial plant operation. As experience has been gained, new regulatory requirements have declined and the number of new and open safety issues have decreased to a small and manageable level. Future NRC regulatory issues at nuclear power plants, including SONGS 1, should continue to focus more on operational issues which do not generally result in plant modifications. Edison expects that any new required plant modifications will be few in number and minor in scope. Such modifications should have only a minor impact on plant operations.

CHAPTER 3

CAPITAL REQUIREMENTS

I

INTRODUCTION

This chapter describes: (1) post-Fuel Cycle 11 1/ capital expenditures for modifications necessary for NRC issuance of a Full-Term Operating License (FTOL) for SONGS 1; (2) capital expenditures for other modifications planned and/or assumed to be required during the post-Fuel Cycle 11 period through March 2007; and (3) the continuing capital expenditures for the Annual Capital Program. When totaled, these capital expenditures represent all capital expenditures assumed to be incurred during the post-Fuel Cycle 11 period through March 2007. Recognizing the uncertainty in forecasting future capital requirements, a range of allowances has been developed for the purpose of evaluating cost-effectiveness, as discussed in Section III.A. This range of capital expenditures represents the cost against which the net operating benefits of post-Fuel Cycle 11 operation are compared to determine the overall cost-effectiveness of continued SONGS 1 operation.

All costs shown in this chapter are at 100 percent share. These costs are then adjusted to Edison share in the Chapter 5 cost-effectiveness analysis.

II

CAPITAL EXPENDITURE REQUIREMENTS FOR THE POST-FUEL CYCLE 11 PERIOD THROUGH 2007

A. Modifications in Response to NRC Requirements for an FTOL and Other Modifications Planned Prior to Post-Fuel Cycle 11 Operation

As described in Chapter 2, following a lengthy period of performing modifications and other actions in response to NRC requirements, the January 2, 1990 Order was issued to document the remaining modifications and other actions requiring resolution in connection with FTOL issuance. These modifications and other actions include all remaining work from the Systematic Evaluation Program (SEP), the Three Mile Island (TMI) Action Items, and other work resulting from NRC requirements.

Modifications to SONGS 1 can be categorized as required for the following five reasons:

1. To comply with changes in NRC requirements unique to the SONGS 1 site. No future modifications are anticipated in this category.

2. To comply with NRC requirements that are unique to SONGS 1, because of its "demonstration plant" origin. This category includes modifications to resolve SEP topics. 2/

1/ Post-Fuel Cycle 11 operation is forecast to begin in January 1994.
2/ See Chapter 2 for a description of the SEP.

After FTOL requirements are met, no further modifications in this category are anticipated.

3. To comply with changes in NRC requirements generic to the nuclear industry. Modifications to resolve TMI Action Items and Generic Safety Issues (GSIs) are examples of this category.

4. To maintain the reliability of SONGS 1 operation. This category includes replacing aging systems with upgraded systems of current design. For example, instrumentation systems or battery systems must be replaced as they approach the end of their useful economic life.

5. To improve the cost-effectiveness of SONGS 1 operation. This category includes plant betterments which lower the overall cost of production.

The forecast capital expenditures for Fuel Cycle 12 3/ are shown in Table 3-A below:

3/ These capital expenditures permit the continued operation of SONGS 1 beyond Fuel Cycle 11.

3 - CAPITAL REQUIREMENTS

Table 3-A

Forecast Capital Expenditures for Fuel Cycle 12 4/

Items	$Millions 100% Share With Corp Ohds
1. Changes in NRC Requirements Unique to the SONGS 1 Site	0
2. Changes in NRC Requirements Unique to SONGS 1	11
3. Changes in NRC Requirements Generic to the Industry	84
4. Changes to Maintain Reliable SONGS 1 Operation	1
5. Changes to Improve Cost-Effectiveness	0
6. Allowance	12
Subtotal	108
Annual Capital Program 5/	17
Total	125 6/

During the period 1980 through 1993, significant modifications will have been completed on SONGS 1, including the three most important areas of regulatory related modifications (i.e., SEP, TMI Action Items, and seismic upgrades 7/). The outages required to implement these modifications have significantly reduced the overall unit capacity factor during this period. Following FTOL issuance and completion of the modifications required by the January 2, 1990 Order, the Unit will conform to current safety standards. 8/

Categories 2 and 3 above represent the final $95 million of modification work required for SONGS 1 to obtain an FTOL. Over 80 percent of these modifications required for FTOL issuance result from changes in NRC requirements which occurred before 1986. After obtaining the FTOL and

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4/ See Appendix I for a complete list and description of planned modifications.
5/ The cost for the Annual Capital Program for Fuel Cycle 12 is included here (from Section II.B) to obtain the total capital expenditure projection for Fuel Cycle 12.
6/ Assumes SDG&E Corporate Overheads are at the same rate as Edison's.
7/ See Chapter 2.
8/ See Chapter 2.

completing this work, SONGS 1 will enter a period of fewer modifications due to changes in NRC requirements, similar to its first 12 years of operation and similar to the experience of comparable plants with FTOLs. 9/ Categories 4 and 5, above, are subject to change and evolution based on continuing assessments of plant conditions, resource priorities, and cost-effectiveness.

A complete list and description of the modifications currently planned prior to post-Fuel Cycle 11 operation is included in Appendix I. The current cost forecast for each of these modifications is shown in Appendix J. 10/

An allowance is provided for potential new items or detailed changes in the current items for all modification categories. As always, there is the possibility of changes in NRC requirements or priorities. However, because most of the Fuel Cycle 12 modifications are based on the January 2, 1990 Order, and because they are scheduled for the very next refueling outage, it is very unlikely that the list of NRC-mandated items will increase.

The refueling outage for Fuel Cycle 12 is currently scheduled to start in the fourth quarter of 1992. Planning, conceptual engineering and studies, estimate preparation, long lead-time procurement activities, and ongoing NRC submittals for the planned modifications began in early 1990. Capital expenditures for these items are currently approximately $20 million (100% share). These initial expenditures were necessary to enable timely preparation for the modifications scheduled to occur during the Fuel Cycle 12 refueling outage. However, at this time, most of the remaining Fuel Cycle 12 expenditures have been delayed until cost-effectiveness has been addressed in the BRPU proceeding. The current Fuel Cycle 12 costs are included in the $125 million of Fuel Cycle 12 capital expenditures for the purposes of the cost-effectiveness evaluation.

B. Annual Capital Program

The Annual Capital Program consists of all routine, ongoing capital expenditures required for continued reliable operation of SONGS 1. The Annual Capital Program includes capitalized spare parts and tools, replacement of capitalized components, and the Design Bases Documentation (DBD) program. 11/ The DBD program is a continuing administrative process to organize, consolidate, and update design information to support operation, maintenance, and modification of the plant. The DBD program started in 1988 and is forecast to be complete by 1997.

9/ See Chapter 2.

10/ The cost forecast in Appendix J are all at a "pre-conceptual," "conceptual," or "preliminary" estimate level.

11/ The incremental costs for spare parts, tools, and replacements and the total costs for the DBD program are contained in the Cost-Effectiveness Analysis.

The projected costs for the Annual Capital Program are trended from the costs in prior years for capitalized spare parts, tools, and component replacements, whereas the projected costs for the DBD program are based on specific plans and/or allowances. The projected cost for the Annual Capital Program is $8 million per year.

C. <u>Modification Requirements Projected for the Post-Fuel Cycle 12 Period Through March 2007</u>

For the purposes of this analysis, refueling outages for the post-Fuel Cycle 12 operation period are forecast to occur as set forth in Table 3-B below:

Table 3-B

<u>Schedule of Future Operation</u>

Fuel Cycle No.	Refueling Outage	Operation
11	N/A	03/91 - 11/92
12	11/92 - 01/94*	01/94 - 09/95
13	09/95 - 12/95	12/95 - 09/97
14	09/97 - 11/97	11/97 - 08/99
15	08/99 - 11/99	11/99 - 07/01
16	07/01 - 10/01	10/01 - 07/03
17	07/03 - 10/03	10/03 - 06/05
18 12/	06/05 - 09/05	09/05 - 03/07

* Includes the effect of delayed Fuel Cycle 12 expenditures.

Capital expenditures projected for the post-Fuel Cycle 12 operation period are considered in two categories: (1) future modifications; and (2) the Annual Capital Program. The projected cost of future modifications is based on an analysis of the rate of new modifications for SONGS 1 in recent years. The Annual Capital Program is discussed in Section II.B. In addition to forecasting future costs based on SONGS 1 specific information, the total projected annual capital expenditures were also compared to a group of peer nuclear plants, as discussed in Section II.D.

No specific plant modifications are currently required by the NRC for implementation following the Fuel Cycle 12 refueling outage. However, Edison does plan to make a betterment modification in Fuel Cycle 13 as described in Section II.E. Also, ongoing analyses could potentially identify a need for plant modifications beyond Fuel Cycle 12 as described in Chapter 2, Section II.B.2.

Because no specific plant modifications are currently required by the NRC following the Fuel Cycle 12 refueling outage, Edison has developed an allowance for future requirements for periods after Fuel Cycle 12

12/ Fuel Cycle 18 is the last operating cycle considered in the cost-effectiveness analysis.

based on an assessment of the recent history of emergent 13/ plant modifications for SONGS 1 and comparison to a peer group of PWRs. Cost-effectiveness sensitivity to variation in this allowance is discussed in Section III.A.

Emergent plant modifications for SONGS 1 come from two sources.

1. NRC requirements generic to the industry.

2. Changes to maintain reliable operation.

As discussed in Chapter 2, after FTOL issuance and completion of Fuel Cycle 12 modifications and other actions, further plant modifications due to changes in NRC requirements are expected to be relatively few and less significant in scope. Edison reviewed emergent modification work on SONGS 1 due to changes in NRC requirements during the period mid-1985 to mid-1990 to develop a cost projection for future years. That review resulted in an allowance of $6 million per year for modifications due to future changes in NRC requirements beyond Fuel Cycle 12. This rate of emergent modifications due to changes in NRC requirements is expected to continue, or likely decrease, in the future, as discussed in Chapter 2.

An Edison assessment of changes to SONGS 1 to maintain reliable operation during the two-year period from mid-1988 to mid-1990 indicated that $13 million (100% share) per year was the rate of emerging modifications in this category. This rate is expected to be similar or lower in the future.

Therefore, based on the recent history of emergent modifications at SONGS 1, an allowance was developed for capital modification requirements for the post-Fuel Cycle 12 operation period through March 2007 as shown in Table 3-C. This allowance was developed such that it represents a level of emergent modifications which is not likely to be exceeded.

13/ "Emergent" refers to required modifications that are identified/ discovered during the time period being assessed. This is differentiated from plant modifications that have been required from earlier time frames.

Table 3-C

Edison and SDG&E Share
SONGS 1 Annual Capital Expenditures
Allowance for Post-Fuel Cycle 12

(Expressed in 1990 $)

	Annual $
Modifications	
NRC Requirements Generic to the Industry	6 million
Changes to Maintain Reliable Operation	13 million
Subtotal	19 million
Annual Capital Program 14/	8 million
Total	27 million

Recognizing that future fuel cycles are projected to last approximately 2 years, the allowance for Fuel Cycle 13 capital requirements from Table 3-C is $70 million, including escalation. Allowances for later fuel cycles are lower to reflect the reduced need for additional capital expenditures as the plant approaches the end of its licensed operating period. Therefore, the allowance developed for the post-Fuel Cycle 12 capital requirements is as follows:

Table 3-D

Edison and SDG&E Share Allowances for
Post Fuel Cycle 12 Capital Expenditures

Fuel Cycle	$Millions 100% Share
13	70
14	70
15	60
16	50
17	40
18	40

As discussed earlier, the rate of modifications due to changes in NRC requirements is expected to be much lower in the future. Also, the rate of emergent modifications to maintain reliable operation is likely to decrease because of the comprehensive reviews of the Unit that have been conducted in recent years to comply with existing NRC requirements.

14/ The annual cost for the Annual Capital Program is included here (from Section II.B) to obtain a total annual capital expenditure projection.

Therefore, the allowances in Table 3-D for post-Fuel Cycle 12 capital requirements are considered more than adequate for the most likely future capital expenditures. Two lower capital requirements cases are provided in Section III.A as a sensitivity for this input parameter.

D. Comparison to Comparable Plants in the Industry

Edison visited five plant sites in 1990 15/ to specifically assess their capital requirements status and forecasts. The seven units at the five plant sites have FTOLs and have previously met the significant number of NRC requirements from the late 1970s and early 1980s. During these visits, Edison confirmed that these plants represent conditions considered applicable to SONGS 1 after the Fuel Cycle 12 refueling outage. A review of the capital expenditure records and forecasts at these plants shows an average annual rate of capital requirements of $24 million (expressed in 1990 dollars) for these plants.

Therefore, this comparison with a peer group of plants supports an allowance for SONGS 1 capital expenditures of $27 million per year (1990 dollars) or less for the post-Fuel Cycle 12 operation period.

E. Planned Betterment Modification for Fuel Cycle 13

In order to minimize continuing corrosion of the steam generator tubes, the plant is currently operated at a reduced reactor coolant temperature. This results in normal turbine generator output at about 90 percent of its rated capability. A modification to the High Pressure Turbine is planned for the Fuel Cycle 13 refueling outage which will allow increased steam flow and thus provide a substantial increase in the electrical power output of the unit. This modification will not increase the rated capacity of SONGS 1 above the 436 MW included in the CEC's ER-90 Resource Plan, and does not extend the life of SONGS 1. The cost forecast for this modification is $15 million (1995 dollars). The life cycle operating benefit for this modification will be about $45 million (100 percent share, January 1993 present worth). The cost for this discretionary betterment modification is the first identified use of the allowance for Fuel Cycle 13 as developed in Section II.C.

15/ To evaluate post-FTOL, post-Fuel Cycle 11 operation of SONGS 1 in terms of industry experience, Edison has studied the experience of a peer group of seven Westinghouse Pressurized Water Reactors (PWR) at five sites. These sites and their year of initial operation are: Connecticut Yankee - 1968; Ginna - 1970; Point Beach - 1970; Prairie Island - 1973; Kewaunee - 1974.

III

POTENTIAL DEVIATION

A. Sensitivity

Section II.A provides a base-case forecast for Fuel Cycle 12 capital requirements and Section II.C develops an allowance for post-Fuel Cycle 12 capital requirements. The Fuel Cycle 12 capital requirements forecast is based on an early level of conceptual engineering. The post-Fuel Cycle 12 capital requirements allowance is based on SONGS 1 emergent modifications in recent years and a comparison with a peer group of plants and is considered more than adequate for the most likely future capital expenditures (as discussed in Section II.C).

Recognizing the uncertainty in forecasting future capital requirements, it is appropriate to consider a potential range of capital requirements for each fuel cycle. A reasonable range for consideration as a sensitivity of future capital requirements is as shown in Table 3-E below. For Fuel Cycle 12, the sensitivity is based on the current status of engineering development for the specific planned modifications and the potential for other modifications not yet identified. For Fuel Cycles 13-18, the sensitivity is based on the "high case" allowance developed in Section II.C and judgment as to two possible lower level of capital expenditures that might actually be required. This range of allowances does not include the potential for steam generators replacement, which is discussed separately below.

Table 3-E

SONGS 1 Capital Expenditures Sensitivities 1/

($ in Millions, 100% Share, Year of Expenditure)

Fuel Cycle	Low	Medium	High
12	125	125	140
13	50	60	70
14	50	60	70
15	40	50	60
16	30	40	50
17	20	30	40
18	20	30	40
Total	335	395	470

1/ For Fuel Cycle 12 the "medium case" in this table comes from Table 3-A. For Fuel Cycles 13-18, the "high case" comes from Table 3-D.

B. Steam Generators Condition

1. Introduction

Steam generators are large heat exchangers located inside the reactor containment where steam is produced from the reactor heat. The steam then leaves the containment in large pipes and is used to spin the turbine generator to produce electricity.

All PWRs have steam generators. SONGS 1 has 3 steam generators, each weighing about 200 tons. Each steam generator contains internally about 3,800 small tubes. Thus SONGS 1 has approximately 11,000 steam generator tubes. Inside the tubes is reactor water which has been heated by the nuclear fuel and which returns to the reactor when it has transferred its heat to produce the steam. Outside the tubes and surrounding them is turbine plant water which boils to produce the steam used to spin the turbine generator.

The O&M costs included in Chapter 4 provide for maintenance of all SONGS 1 equipment including the steam generators through the end of the evaluation period. The capital cost allowances discussed above in Section II provide for replacement of equipment, including pumps, valves, instrumentation and other components such as heat exchangers as may be necessary to maintain reliable operation but do not contain an allowance for replacement of the steam generators.

The possibility that the SONGS 1 steam generators would be replaced, and the impact of that work on the results of the cost-effectiveness evaluation, are discussed in this section.

2. Background

The SONGS 1 steam generators are maintained in accordance with NRC requirements during periods when the reactor is shut down. Manways are opened, providing access to various parts of the steam generators, including both to the inside and (to a very limited extent) to the outside of the steam generator tubes. Inspections and pressure tests are then conducted to locate and repair any leakage from the inside (normal pressure about 2,000 psi) to the outside (normal pressure about 600 psi) of the tubes. Such leakage is undesirable and is limited by NRC requirements.

Repairs to the steam generators include inserting plugs into the ends of leaking tubes to remove them from service and prevent leakage or inserting slightly smaller diameter tubes, called "sleeves," inside a portion of the existing tubes to minimize or eliminate leakage. The steam generators were constructed with substantially more than the minimum-required number of tubes, in order to account for such repairs during their life.

Other maintenance performed at the same time involves flushing to remove material from the outside of the tubes, where it tends to accumulate as the turbine plant water boils and is removed as steam. The reactor water and the turbine plant water are normally maintained at high levels of purity. However, over years of operation various forms of corrosion and metallurgical degradation occur, requiring repairs to be performed on all PWR steam generators.

Similar to other PWRs, SONGS 1 has had repairs done on its steam generators. In an extended outage in 1980-1981, SONGS 1 had sleeves inserted into more than 6,000 steam generator tubes, and plugs into more than 600 others, in a major repair program. This was required in response to corrosive attack on the outside of the tubes resulting from caustic deposits which could not be removed by flushing. In addition, in order to decrease the rate of corrosion, normal reactor temperature was decreased slightly, resulting in a reduction of about 50 MWe in generator output. In the ten years of operation following this major repair program, about 500 additional tubes have been plugged for various reasons. Including the tubes plugged before 1980, the total number of tubes plugged to date is approximately 1,450.

There are PWRs in which more tubes have had to be removed from service than provided for in the original design margin, and consequently, steam production and turbine generator output have been reduced. Often this has led to programs to replace steam generators in order to maintain, or increase, output and unit reliability and reduce maintenance costs.

Thus far, 12 PWRs worldwide (9 in the U.S.) have had their steam generators replaced. Approximately 20 others in the U.S. are in various stages of planning for replacement.

3. Forecast

The cost-effectiveness sensitivities included in Chapter 5 are based on maintenance of the existing steam generators. SONGS 1 capacity factor and costs reflect a continuation of current experience with respect to operation and maintenance of the steam generators, through March 2007. An assumed loss of 1.5 MWe per fuel cycle has been included in the cost-effectiveness evaluation to account for additional tube plugging through the end of the license period.

Typically, the steam generators are inspected and tubes plugged only during the planned refueling outages. Enough time has been allowed in the future planned refueling outages (90 days) to do all required inspections and all anticipated repairs. In addition, there is enough unallocated outage time allowed within the overall capacity factor projection (70 percent) to accommodate mid-cycle outages that could be required for steam generator inspections/ repairs.

Edison continually reviews and assesses the condition of the steam generators and also reviews developing problems and corrective actions at other plants worldwide. Techniques for steam generator maintenance continue to improve, so that repairs in response to any future increase in degradation will likely be more practical and effective than before.

It is anticipated that the current steam generators will continue to provide acceptable service for the duration of the currently planned licensed operating period (March 2007). Based on experience to date, it is forecast that the steam generators will provide acceptable service at least through Fuel Cycle 14 (1999). Nevertheless, as with other PWRs, continued maintenance of the existing steam generators and continued capacity reductions could become less cost-effective than replacement as a result of unanticipated accelerated degradation.

4. Possible Replacement

Particularly in the event that a 20-year extension of the NRC Operating License is sought (see Chapter 2), the additional generator output and reduced maintenance costs that could be achieved with new steam generators would make replacement economically attractive. 16/

As indicated above, many PWRs either have, or are making plans to, replace their steam generators. Accordingly, the cost and benefit impact of replacement of the SONGS 1 steam generators has been assessed as part of the scenarios considered in Chapter 5.

A decision to proceed with the engineering and procurement activities for a steam generator replacement needs to be made about 4 years before the outage in which the replacement is planned. Use of current maintenance practices is assumed to continue to support operation from the time when a decision is undertaken to proceed with replacement, until the refueling outage when replacement is to occur. At that time, a six-month outage would be required to complete the work. Steam generator replacement at SONGS 1 is estimated to cost approximately $200 million (100 percent share, 1991 dollars). Replacement would allow operation of the turbine generator at its full net rating of 436 MW.

Again, steam generator replacement would likely only be pursued in the event that a 20-year extension of the NRC Operating License is sought. However, there is the possibility of unanticipated accelerated steam generator tubes degradation before 2007, and that life extension would be found not to be viable or for some other reason not pursued. Steam generator replacement and continued plant operation to March 2007 would be reassessed at that time.

16/ See Chapter 5, Section IV.D.

IV

CONCLUSION

When SONGS 1 receives its FTOL, the Unit will have completed an era of major plant modifications and upgrades. Because no plant modifications are currently specifically required for implementation beyond Fuel Cycle 12, the backlog of future plant modifications will be very low. The rate at which new plant modification requirements emerged was demonstrably lower in the late 1980s than in the 1970s and early 1980s. This lower rate is expected to continue through the 1990s. A review of comparable industry plants also supports the forecast that, after the backlog of plant modifications from the 1970s and early 1980s is completed, capital requirements for SONGS 1 will decrease significantly. Recognizing the uncertainty in forecasting future capital requirements, a range of allowances has been developed for the purpose of evaluating cost-effectiveness in Chapter 5. As discussed in Section III.B, it is anticipated that the current steam generators will continue to provide acceptable service for the duration of the currently planned licensed operating period. However, there is also the possibility that steam generator replacement would need to be considered before the end of the current planned operating license period (2007).

CHAPTER 4

OPERATING COSTS

I

INTRODUCTION

This chapter presents the operating expense estimate for SONGS 1. 1/ Long-term operating expenses consist of annual operation and maintenance (O&M) expense, cyclical refueling outage expense, 2/ and nuclear fuel expense. This chapter also describes the methodology used to estimate the O&M expense associated with the alternative scenario to shut the Unit down for the long term following the end of Fuel Cycle 11, pending full decommissioning. The estimate of shutdown O&M expense is included in this testimony only for use in the cost-effectiveness analysis in Chapter 5. 3/ The nuclear fuel expense included for use in this cost-effectiveness analysis is based on the same methodology as the nuclear fuel expense estimates in Edison's current Energy Cost Adjustment Clause (ECAC) proceeding. The ongoing review of nuclear fuel expense will be in the ECAC proceeding. The nuclear fuel expense includes incremental costs associated with the uranium fuel cycle, including both mining and related activities and the disposal of waste streams.

II

LONG-TERM OPERATION AND MAINTENANCE EXPENSE

Long-term O&M expenses include annual O&M expenses and cyclical refueling outage expenses. Forecasts for future years are developed from the estimate of San Onofre nuclear production costs for Test Year 1992 in Edison's testimony in the 1992 GRC and may vary from year to year depending upon whether there is a refueling outage.

The basis for SONGS 1 O&M expenses in 1992 is shown below:

1/ All costs in this section represent 100 percent share. These costs are adjusted in the cost-effectiveness analysis for Edison's 80 percent share.

2/ Cyclical refueling outage expense includes incremental costs required each time the Unit is shut down for refueling.

3/ In Chapter 5, the percentage of O&M expense continuing after a shutdown of SONGS 1 estimated in this chapter is applied to estimates of future SONGS 1 O&M expenses derived from O&M expenses in Edison's testimony in the 1992 GRC.

4 - OPERATING COSTS

Table 4-A

SONGS 1 O&M Expense

(1992 Dollars in Millions)

100% Data

Base	$67.7	Per Year
Refueling	17.2	Per Refueling Outage
TOTAL	$84.9	

The cyclical refueling outage expense shown above represents the incremental costs required each time the Unit is shut down for refueling, as it will be in 1992. Examples of the major activities which occur during the refueling outage include: (1) execution of the actual refueling activities (fuel movement); (2) corrective and preventative maintenance that cannot be performed while the Unit is operating; and (3) in-service testing and inspections of equipment not accessible during operation.

After Fuel Cycle 12, refueling outage durations should be comparable to similar plants that have received FTOLs. Comparable plants in the industry have an average refueling outage length of 82 days after the first two refueling outages following completion of Three-Mile Island (TMI) modifications. 4/ While SONGS 1 can expect refueling outages to be about 70-80 days, outage durations have been conservatively projected to be 90 days.

III

NUCLEAR FUEL EXPENSE

The forecast nuclear fuel expense is presented in Table 4-B on an average annual cents/kWh basis. The nuclear fuel expense cost components, other than the financing costs, are calculated by the same methodology used in Edison's annual ECAC proceedings. The nuclear fuel expense for a given year is the projected SONGS 1 net electric generation divided into the sum of the following cost components: (1) that portion of the nuclear fuel cost, including pre-reactor cost of capital, amortized during the year; (2) in-core carrying costs, based upon the unamortized value of the fuel in the reactor; and (3) the spent fuel disposal charge paid to the Department of Energy mandated under the Nuclear Waste Policy Act of 1982.

4/ Comparable plants in the industry are PWRs less than 800 MW, representing 64 cycles of operation for 14 nuclear units.

Table 4-B

Nuclear Fuel Costs

Year	Fuel Cost * (Cents/kWh)
1994	1.71
1995	1.56
1996	1.25
1997	1.22
1998	1.32
1999	1.31
2000	1.40
2001	1.42
2002	1.52
2003	1.58
2004	1.68
2005	1.78
2006	1.85
2007	2.00

* @ 70% Capacity Factor

Edison's policy is to include all financing costs in economic analyses. As a result, the pre-reactor cost of capital and in-core carrying costs are based upon Edison's overall cost of capital. As Edison demonstrated in another Commission proceeding, 5/ the overall cost of capital is the appropriate cost to use in fuel economic analyses. The overall cost of capital considers all costs of financing nuclear fuel, including the equity required to support the Company's borrowings 6/ and the costs of interest rate risks. Using this overall cost of capital results in a higher forecast of nuclear fuel expense than using the short-term debt rate alone because all appropriate costs are incorporated.

Forecasts of material and services costs for manufacturing SONGS 1 nuclear fuel are based on contract prices and market price projections. Contracts are in place for a majority of SONGS 1 fuel requirements for the remainder of the currently anticipated license period of the Unit. Consultant studies were used to develop market price projections for fuel requirements not covered by existing contracts or where the contract price is market-price related. The spent fuel disposal charge set by the federal government and paid to the Department of Energy is 0.1 cents/kWh of net electric generation.

5/ See ECAC Application No. 88-02-016 proceeding, Exhibit No. 187, Prepared Rebuttal Testimony of C. Alex Miller, dated March 1989.

6/ As described in Edison's 1989 Cost of Capital Decision No. 89-11-068, p. 28, reductions in the percentage of equity in a company's capital structure will lead investors to require a higher return on common equity and a higher debt rate.

IV

SHUTDOWN OPERATION AND MAINTENANCE EXPENSE

Edison conducted a thorough analysis of the reduction in O&M expenses if SONGS 1 is shut down prior to March 2007. That analysis shows that after the first two years, approximately 48 percent of the annual O&M expenses will continue to be incurred with SONGS 1 shut down. This percentage is applied to the forecast long-term O&M expense to derive the annual "shutdown O&M expense" level. The result represents the level of O&M expense that will continue to be incurred until SONGS 1 is decommissioned under this shutdown scenario. The shutdown analysis used Edison's 1990 Nuclear O&M expense budget 7/ to derive an estimate for the remaining O&M expense levels if SONGS 1 was no longer operating. The 1990 budget was chosen because it provides the most complete estimate of the detailed tasks required to operate and maintain SONGS 1. 8/ The 1990 budget basis for the shutdown analysis was $68 million (in 1990 dollars).

A detailed evaluation was performed of the functions and costs required for long-term shutdown of SONGS 1. Cyclical refueling outage expenses would not be incurred in a shutdown environment and are therefore excluded from this analysis. The SONGS 1 shutdown scenario is based on the following:

1. SONGS 1 would be in a long-term shutdown mode through March 2007.

2. SONGS 1 would continue to be part of the active SONGS, responsible for an appropriate share of common site support costs including security, emergency preparedness, non unit-specific training, and administration.

3. All fuel would be offloaded from the core and placed in the SONGS 1 spent fuel pool.

4. Pending removal, appropriate protective actions would be taken to prevent systems and equipment deterioration which could result in a hazard.

5. Ventilation systems in the spent fuel building would remain operable.

6. Radiation monitoring systems would remain operable for all areas containing radioactive materials, as well as any areas in which radioactivity could be inadvertently released.

7/ Edison's 1990 budget for SONGS 1 O&M expenses is used here for purposes of the cost-effectiveness analysis of continued operation of SONGS 1 and is not the basis for any rate relief requested in this Application.

8/ Nuclear O&M costs were estimated in the 1992 GRC using a methodology that trended total costs from an historical base. That O&M estimate is not in sufficient detail to develop O&M expenses under a shutdown mode. For that reason, the 1992 GRC testimony was not used to establish a percentage for use in the cost-effectiveness analysis for shutdown O&M.

7. Power plant buildings, including some offices, shop facilities, and the exterior of SONGS 1 structures, will be maintained as required during shutdown.

Using these parameters, the minimum functions required to be performed were carefully evaluated to estimate the costs for this long-term shutdown scenario. This evaluation was based on a combination of Edison's operating experience at SONGS 1, discussions with Rancho Seco 9/ personnel regarding their costs in a plant shutdown mode, and reviews of data from other plants in a shutdown mode.

Under the shutdown scenario, some functions were eliminated and others were reduced. This evaluation identified that approximately $32.7 million, or 48 percent, of the 1990 O&M expense would continue to be incurred with the unit shut down under the conditions described above. Table 4-C identifies the long-term operating and shutdown O&M expense by organizational division. The 48 percent factor derived from the above evaluation was applied to the annual O&M expense to establish shutdown costs after a two-year phase-down period.

The phase-down period describes the transition from full operation to the shutdown condition. This period is assumed to be two years. During the first year, O&M expense would be 85 percent of the full O&M expense. During the second year, O&M expense would be 65 percent of the full O&M expense.

9/ Rancho Seco is currently in a "shutdown" mode, similar to that assumed for SONGS 1 in this analysis, rather than a "mothball" mode. The difference in the two modes is that under a "mothball" mode (as defined in NRC Regulatory Guide 1.86), all fuel assemblies, radioactive fluids, and waste have been removed from the site and the site security and radiation monitoring/surveillance would be consistent with a Possession Only License rather than an Operating License. The O&M costs for a single unit site such as Rancho Seco in a shutdown mode are different in many ways from a unit at a multiple unit site such as San Onofre; therefore, although the discussions with Rancho Seco personnel on shutdown costs were informative, they were not used as direct inputs to the costs for the SONGS 1 shutdown scenario.

TABLE 4-C

SONGS 1 O&M EXPENSE

(All Costs in Millions of 1990 Dollars)

(Costs at 100%)

Line No.		Plant in Operation (1)	Plant Shutdown (2)
1.	NGS Divisions		
2.	Maintenance	11,282.6	3,432.8
3.	Operations	5,534.6	2,004.6
4.	Technical Engineering	6,020.0	899.8
5.	Health Physics	3,897.0	1,720.5
6.	Admin. & Facilities	6,640.0	4,530.0
7.	Security	2,942.9	2,770.1
8.	Emergency Preparedness	1,776.4	1,175.5
9.	Nuclear Information Services	2,300.0	2,050.0
10.	Material Support	1,840.0	1,455.5
11.	Budgeting & Administrative	1,980.0	1,107.4
12.	Substance Abuse Program	376.7	242.7
13.	Station Management	142.5	88.1
14.	Training	4,409.2	1,789.6
15.	O&M Support	1,040.0	666.5
16.	Outage Management	235.4	85.4
17.	Subtotal	50,417.3	24,018.5
18.	NES&L Division		
19.	Services/Proj Man/Comm.	4,011.2	1,131.9
20.	Nuclear Regulatory Affairs	6,647.2	5,268.2
21.	Nuclear Oversight	2,860.7	1,759.7
22.	Nuclear Engineering/Construction	4,111.3	504.5
23.	Subtotal	17,630.4	8,664.3
24.	Total	68,047.7	32,682.8

25. Calculation - Plant Shutdown Cost Percentage

26. $\frac{\$32,682.8}{\$68,047.7} = .4803 = 48\%$

27.

V

CONCLUSION

In summary, the long-term O&M expense forecast is based on the estimate of SONGS 1 O&M expense used in the 1992 GRC for both base and refueling expenditures. These expense levels are representative of the ongoing costs required to keep SONGS 1 operating.

The nuclear fuel cost components are based on methods consistent with Edison's current ECAC filing on nuclear fuel. Edison's overall cost of capital is used in fuel economic analyses because this methodology includes all costs of financing nuclear fuel.

The relationship between long-term O&M expenses and shutdown costs is based on a detailed evaluation of activities performed at SONGS 1 utilizing Edison's operating experience. The evaluation concluded that 48 percent of long-term O&M expenses would continue under the alternative scenario described.

CHAPTER 5

SONGS 1 - COST-EFFECTIVENESS
SOUTHERN CALIFORNIA EDISON COMPANY

I

VALUE OF SONGS 1 IN THE RESOURCE PLAN

This chapter describes how the San Onofre Nuclear Generating Station Unit No. 1 (SONGS 1) fits into Edison's resource strategy, and describes the cost-effectiveness of continued SONGS 1 operation.

A. Resource Planning Strategy

Edison's planning philosophy recognizes that unforeseen events and uncertainties will affect future plans. Edison has therefore developed a resource planning strategy to best enable it to meet an uncertain future with a reliable, environmentally sound, low-cost supply of electricity. This same goal is embodied in the California Energy Commission's (CEC) Electricity Report process and Commission's BRPU process.

SONGS 1 is an existing resource on an existing site. It has been assumed to be an existing and committed resource in the CEC's Electricity Report 90 (ER-90). Its continued use is consistent with the CEC's and Commission's policies on fuel diversity, environmental improvement, and the maintenance of a reliable, low-cost supply of energy for California.

1. Fuel Diversity

A key element of Edison's resource strategy is to maintain sufficient resource diversity to meet a variety of possible futures. 1/ The achievement in resource diversity is shown by comparing Edison's energy mix for 1980 to 1990:

1/ This resource planning strategy approach is described in detail in Edison's Strategies for an Uncertain Future, dated March 1988, which was submitted to the Commission as a work paper to Exhibit No. SCE-10 in the 1992 GRC, A.90-12-018.

Table 5-1

Edison Energy Mix
(%)

	1980	1990
Oil	28.1	2.4
Gas	30.0	17.3
Nuclear	1.0	19.5
Coal	12.3	12.8
Hydro	9.0	3.0
Utility Purchases	19.6	15.5
PURPA Purchases*	-	29.5
	100.0	100.0

* PURPA purchases comprise power generated from cogeneration, biomass, geothermal, wind, solar, and hydro sources.

Table 5-1 shows that electricity produced in 1980 from oil and gas was over 58 percent of Edison's energy mix. This dependence was not considered to be the best resource strategy for two reasons: fuel security and rate stability. First, a drop in availability of gas could adversely impact the ability to meet customer demands. Greater dependence on gas increases the likelihood of fuel supply problems which in turn could adversely impact system reliability. Second, volatility in gas prices could lead to significant rate variability which can be expensive and disruptive for ratepayers.

During the last ten years, Edison has significantly improved the diversity of its resource mix. Edison's oil/gas dependence has declined from 58 percent in 1980 to a 1990 level of less than 20 percent. Even with purchases from PURPA gas-fired cogeneration resources included, Edison's 1990 gas dependence was still only 38 percent. This reduction was accomplished primarily by additional nuclear generation, utility purchases, and non gas-fired Public Utility Regulatory Policies Act (PURPA) purchases. The non gas-fired PURPA purchases are produced from a diverse set of resource alternatives including renewable resources such as wind, solar, biomass, and geothermal. Edison now uses nine different fuel sources, more than any other utility in the world. This resource diversity means Edison is less affected by changes in the price of any single type of fuel. SONGS 1 contributes to this effort by using nuclear fuel which is forecast to have a stable, low-cost supply well into the future.

SONGS 1 plays an integral role in Edison's resource plan. This Unit can provide about 325 MW of generating capacity and approximately 2,000 GWh of energy annually to the Edison system. 2/ To otherwise supply this generating capacity to the system would require 10,000 acres of land for wind farms or 1,500 acres for solar. To otherwise produce this energy would require: (1) about 3 million barrels of oil; or (2) 20 billion cubic feet of natural gas; or (3) 1 million tons of coal per year; or (4) over 3 million tons of waste. As a nuclear-powered plant, SONGS 1 contributes to resource diversity, which is important to Edison's planning strategy.

Without SONGS 1, Edison would have to rely more on its gas generating resources. For example, using ER-90 data without SONGS 1 at 70 percent capacity factor, approximately 60 percent of the replacement energy would come from gas generation and 40 percent from economy energy and other purchases. 3/ Further details are provided below.

There is a much greater chance of fuel price increases for gas fuel than nuclear fuel, and there is a greater chance of impaired availability of fuel for gas than nuclear. As such, SONGS 1 provides a fuel diversity benefit to the Edison system.

2. Environmental Concerns

Another key element of Edison's resource planning strategy is the pursuit of resource options which provide an environmentally sound energy alternative.

Recently, the attention to air quality has increased with new regulations, both proposed and adopted, by air pollution control districts in California. The value of reducing residual emissions 4/ has been the focus of air quality discussions at the Commission and the CEC, as well as at the federal level during debate concerning the Clean Air Act and a proposed carbon tax. Air quality problems, particularly in the South Coast Air Basin, affect Edison. Clean energy sources, such as nuclear power and renewables, contribute importantly to Edison's effort to improve air quality in our service area.

2/ In Exhibit No. SCE-18 to Edison's 1992 GRC, Edison assumed implementation of a modification to the turbine generator that would enable SONGS 1 to provide 340 MW of generating capacity and approximately 2,100 GWh of energy annually to the Edison system without replacement of the steam generators. Since that exhibit was prepared the timing and details of this modification have been revised so that it will provide about 325 MW and approximately 2,000 GWh annually following implementation.

3/ This is based on replacing SONGS 1 with the least-cost alternative set of resources using the ICEM and ER-90 assumptions as described in detail in Section III of this chapter.

4/ Residual emissions are the emission levels remaining following compliance with emission requirements.

Edison's concern regarding environmental quality has recently been underscored by our commitment to reduce CO_2 emissions by 10 percent by the year 2000. Additionally, Edison has recently agreed to support a new, more stringent version of the South Coast Air Quality Management District (SCAQMD) Rule 1135. 5/ In a recent Los Angeles Times interview, John Bryson was quoted as saying "We've sought to take an absolutely fresh, bottoms up look at appropriate controls on our power plants in the basin, starting from the premise that we have a substantial responsibility if the basin is to have healthy air."

While other environmental quality issues, such as land use and water use also deserve consideration in the planning process, methods and values for dealing with these have been left for future proceedings. 6/ At the present time, the only environmental concern that is being quantified by the CEC and the Commission is air quality.

Nuclear generation at SONGS 1 avoids significant amounts of fossil fuel generation. SONGS 1 does not emit NOx, greenhouse gases, or other air pollutants. If operation of SONGS 1 is discontinued, replacement power would be mostly gas generation, with some increased purchases from coal-fired generation in the desert Southwest and Pacific Northwest.

Most of the gas generation used to replace SONGS 1 would occur in the South Coast Air Basin. Edison is at present subject to various environmental regulations including the SCAQMD Rule 1135. At the present time, Edison is subject to current SCAQMD Rule 1135 which will limit NOx emissions to 0.25 lbs/MWh by the end of 1999. This existing rule has been used for this cost-effectiveness analysis. A more stringent rule has been proposed reducing allowed NOx emissions to 0.15 lbs/MWh. Edison has announced its support for this proposed Rule 1135. In its August BRPU ER-90 Compliance Resource Plan filing, Edison will include a SONGS 1 cost-effectiveness analysis based on this proposed Rule 1135. Environmental benefits may be reduced in that analysis.

Without SONGS 1, Edison's gas units would run more often and total emissions would increase. Such increased emissions have been called residual emissions. For example, using ER-90 data with SONGS 1 not operating between 1994 and 2007, residual NOx emissions from Edison's gas units would increase by about 3,250 tons, and residual NOx emissions from out-of-state coal units would increase by about 7,630 tons.

The value of reduced residual emissions has been debated at the CEC and the Commission. No definitive resolution has yet been achieved. Even though D.91-06-022, the Phase 1B BRPU decision, adopts the SCAQMD values for residual emissions to be used in the

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5/ This proposed SCAQMD Rule 1135 is anticipated to be adopted in July 1991.
6/ D.91-06-022, Finding of Facts 12, 14, and 16.

BRPU ER-90 Resource Plan Compliance filing, the Commission's requirement in D.91-06-022 that a sensitivity may be prepared using SCAQMD values for nonattainment area emissions and Nevada Public Service Commission values for attainment area emissions indicates that these values may be discussed further in BRPU. SCAQMD values represent the revealed preference by the SCAQMD of the value of reducing South Coast Basin emissions. They do not represent either the cost or the revealed preference in out-of-state regions of reducing air emissions. Nevada Public Service Commission values better represent the values for out-of-state emissions.

In order to make use of the data available from the ER-90 Resource Plan, and since the three air basins in Edison's service territory are nonattainment areas, Edison's analysis assumes in-state emissions as defined in the CEC data occur in nonattainment areas, and out-of-state emissions in attainment areas. Assuming operation at 70 percent capacity factor, the value of residual emissions reduction is about $111 million in January 1993 net present value (93 NPV). 7/ When values for the reduction of other residual emissions are included, the total benefit for residual emissions reduction becomes $196 million 93 NPV.

Continued SONGS 1 operation provides significant environmental benefits. Furthermore, appropriate environmental costs associated with the nuclear fuel cycle have been captured and included in the evaluation (see Chapter 1, Section VI.C and Chapter 4, Section I). These include costs associated with uranium mining and processing, waste disposal, and decommissioning. The costs of preparing the uranium to be used as fuel as well as the costs to ultimately dispose of the spent fuel are included in the nuclear fuel costs. The cost of disposal of operational low level waste is included in O&M expense. The cost of decommissioning is also being collected in advance. Therefore, all appropriate costs have been captured.

3. Capital Cost Savings Benefit

SONGS 1 provides about 325 MW of capacity and 2,000 GWh of energy to the Edison system. While Edison currently has excess capacity, the excess is expected to be exhausted by the mid- to late-1990s. Need for additional generation would be advanced if SONGS 1 were no longer included in the resource plan. Using the Iterative Cost-Effectiveness Methodology (ICEM) analysis for determining resource additions in the absence of SONGS 1, and the CEC's ER-90 assumptions, replacing SONGS 1 with the best alternative resources would cost $112 million 93 NPV in capital expenditures. This is primarily due to advancing some geothermal resources.

This capital cost savings benefit replaces the capacity value methodology used in Exhibit No. (SCE-18) in Edison's 1992 GRC application. In the 1992 GRC, Edison valued SONGS 1 capacity at

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7/ Using SCAQMD values for in-state emissions and Nevada Power Commission for out-of-state values.

the cost of a combustion turbine (CT) proxy adjusted by an Energy Reliability Index (ERI) to reflect the need for additional capacity in SONGS 1's absence. This approach is the standard measure of avoided cost used for QF payments. In this application Edison is evaluating the capital cost associated with replacing SONGS 1 with the least-cost alternative resources, not necessarily a CT.

B. Benefits Analysis

The methodology used to evaluate the cost-effectiveness of continued SONGS 1 operation is a "SONGS 1 In/SONGS 1 Out" approach. This approach compares the total costs of operating the system with SONGS 1 to the total costs of operating the system without SONGS 1 and the addition of the most cost-effective alternative resources. The most cost-effective alternatives to SONGS 1 operation have been determined using the ICEM first-year test.

The SONGS 1 In/SONGS 1 Out approach used by Edison to value continued operation of SONGS 1 is one part of the ICEM. The ICEM has been used by the Commission and the CEC to evaluate the cost-effectiveness and timing of new resource alternatives. As discussed below, the ICEM consists of two tests: (1) a life-cycle test; and (2) a first-year test.

The first-year test in the ICEM examines whether the benefits of operating a resource in a particular year are greater than the benefits of deferring for a year the capital expenditure for the resource addition. Since typical resource additions can be built during the future year of choice, deferring a new resource is a viable option.

The ICEM assumes that the proposed resource addition will have the same period of operation regardless of the year of initial operation. However, SONGS 1 is an existing unit. Deferral of SONGS 1 operation would result in fewer years of operation during the period of the SONGS 1 NRC license, rather than the same number of years of operation when timing is optimal. As a result, three potential alternatives are possible: (1) continued operation of the Unit through March 2007; (2) temporary shutdown of the Unit; and (3) permanent shutdown. While temporary shutdown is most closely analogous to deferral of a new unit, temporary shutdown of SONGS 1 is not an economically viable option because as explained in Chapter 1: (1) deferral would result in a shortened unit life; (2) continuing O&M costs would be significant; and (3) operating personnel would have to be retrained or kept on the payroll during deferral.

Decision (D.) 91-03-058, which removed SONGS 1 issues from the 1992 GRC to the BRPU, stated that "Various factors, such as NRC requirements, may constrain SONGS 1 capital expenditures to commence during the time between Fuel Cycles 11 and 12. Such constraints--if indeed they exist--mean simply that the first year test would not be run." As explained in Chapter 2, pursuant to the January 2, 1990 Order by the NRC, such constraints do exist, and as explained in Chapter 1, SONGS 1 is a nondeferrable resource. As a result, the first-year test should not be used for SONGS 1. The life-cycle test is, then, the only methodology appropriate to evaluate the benefits associated with SONGS 1.

C. Reference Case and Sensitivities

In this analysis, Edison uses the CEC's ER-90 Resource Plan for its reference case. 8/ Some minor assumption updates agreed to by Edison and DRA witnesses in Edison's 1992 GRC have been included in this reference case. 9/

The reference case uses ICEM to compare the costs of the ER-90 Resource Plan which assumes SONGS 1 operation to the costs of an ER-90 Resource Plan which removes SONGS 1. By applying ICEM we can identify the best resource alternatives to the operation of SONGS 1. If the costs of continued SONGS 1 operation are less than the costs required to build and operate a system not including SONGS 1, then SONGS 1 would be cost-effective.

Many uncertainties could ultimately affect the cost-effectiveness of SONGS 1 continued operation. Even though the ER-90 Resource Plan represents a reasonable forecast on which to base a decision, some assumptions of that forecast, and other forecasts in Edison's SONGS 1 In/SONGS 1 Out cost-effectiveness analysis, may not be realized. To illustrate the potential effect of this uncertainty on SONGS 1 cost-effectiveness in addition to an ER-90 reference case, and a BRPU required case, 30 other sensitivities have been developed. As shown in Figure 5-1, the sensitivities are all based on the ER-90 Resource Plans with and without SONGS 1, but change some of the assumptions used in these plans. These sensitivities include all reasonable combinations of capacity factors, capital requirements, gas prices, and residual emission values. The High (H), Medium (M), and Low (L) values are described in further detail in Section III.F of this chapter.

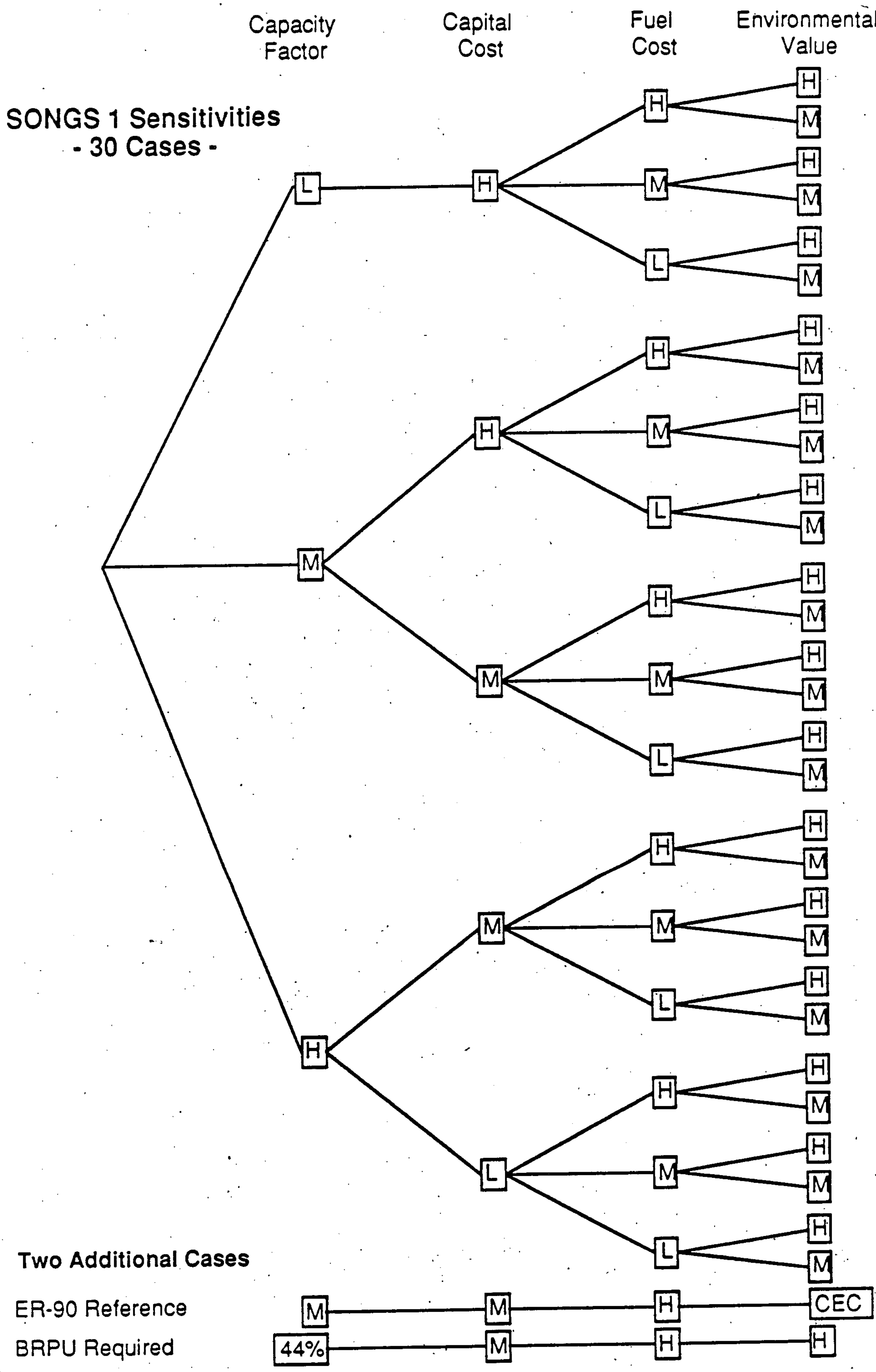
These sensitivities represent a wide range of possible outcomes for SONGS 1 cost-effectiveness. While these outcomes have a broad range, the majority of the sensitivities, including those using medium values for key assumptions, show that SONGS 1 continued operation is cost-effective. However, a key element of net benefit for continued SONGS 1 operation is the value assumed for avoiding residual emissions. If the value of avoiding residual emissions should change significantly, the net benefit of continued SONGS 1 operation could change.

As stated above, four key input parameters have been evaluated to estimate the range of SONGS 1 cost-effectiveness:

8/ This is because "great weight" is to be given to ER-90 in the BRPU per Commission decision.

9/ The minor assumption changes consist of increasing to 1 the probability of success on Caithness geothermal and Argus cogeneration projects. Other than these adjustments, this is the same case used by Edison in SCE-18 of the GRC.

FIGURE 5-1


Capacity Factor
Capital Cost
Fuel Cost
Environmental Value
SONGS 1 Sensitivities
- 30 Cases -
Two Additional Cases
ER-90 Reference
BRPU Required
44%
CEC

1. Capacity Factor

As noted in Chapter 1, SONGS 1 should achieve a capacity factor of 70 percent during the post-Fuel Cycle 11 period through March 2007. A range of average capacity factor performance over the period needs to be considered, however. As such, these sensitivities will consider capacity factors as high as 80 percent and as low as 60 percent as was discussed in Chapter 1. The BRPU required case, a 44 percent capacity factor case, based on a 5-year historical average was analyzed to comply with a prior Commission order. However, this historical period reflects the impact of extended outages to perform modifications required due to changes in NRC requirements; consequently, a 44 percent capacity factor is inappropriate for evaluating performance during an operating period following completion of these required modifications.

2. Gas Prices

During 1985, natural gas prices dropped significantly due to what was called at the time a gas "bubble." This seemingly temporary oversupply of natural gas was assumed to be of limited duration. As a result, most gas price forecasts showed a significant increase in gas prices after several years of low gas prices. As time passed, estimates of gas supply continually increased, so the gas "bubble" was redefined as a gas "sausage" and the time until gas prices would rise back to pre-1985 levels was extended in most gas forecasts. Also, in the late 1980s forecasts began to assume that natural gas and oil prices were not necessarily linked.

Some current gas price forecasts assume that by the end of the decade the gas bubble will have burst and prices will be rising at eight percent annually or more. Other current gas price forecasts assume that gas prices will not rise much, if at all, until beyond 2000. The CEC gas price forecast is high compared with most of today's estimates. For example, the CEC ER-90 forecast a 1991 price of $3.79 per MMBtu, whereas our current price for gas is $2.64 per MMBtu. 10/

The 30 sensitivities developed by Edison consider three alternative gas price forecasts: (a) the CEC fuel prices used in ER-90 ($7.09/MMBtu by 2000); (b) the Southern California Gas Company's forecast as published in the 1990 California Gas Report ($5.56/MMBtu by 2000); and (c) a low gas forecast that includes no escalation before 1995 and five percent per year thereafter ($3.06/MMBtu by 2000). The development of the low gas price forecast is predicated on the assumption that significant coal seam gas from San Juan will be available and additional gas pipelines to the Northwest and Southwest will increase California's access to inexpensive gas.

10/ May 1991 Avoided Cost Energy Pricing Update. This covers the period May 1, 1991 to July 31, 1991.

3. Value of Residual Emissions

One of the benefits of SONGS 1 operation is the avoidance of emissions from fossil-fueled generating plants. These emissions have been valued in the ER-90 Resource Plan as well as in D.91-06-022 in Phase 1B of the BRPU. Edison's reference case will use the emission values identified in the ER-90 Resource Plan. D.91-06-022 requires that Edison's ICEM analyses use SCAQMD emissions values, but also requires a sensitivity to be prepared using SCAQMD emission values in nonattainment areas and Nevada Public Service Commission emissions values in attainment areas. 11/ In order to make use of the data available from the ER-90 Resource Plan, and since the three air basins in Edison's service territory are nonattainment areas, Edison's analysis assumes in-state emissions occur in nonattainment areas, and out-of-state emissions in attainment areas.

4. Capital Costs

A capital cost sensitivity is provided in Chapter 3, Section III.A, and is utilized in the 30 sensitivities discussed in this chapter.

D. Steam Generator Scenarios

Another uncertainty in continued operation of SONGS 1 is the condition of the steam generators. The replacement of the steam generators would require a significant capital expenditure. When deciding whether to make significant capital expenditures on a unit, the duration of the unit's life must be carefully considered. Four scenarios considering the impact of potentially accelerated steam generator degradation were analyzed. These included: (1) early shutdown of SONGS 1; (2) replacement of steam generators without life extension; (3) replacement of steam generators with a 20-year life extension 12/; and (4) increased degradation of Unit capacity due to accelerated steam generator tube corrosion without replacement of the existing steam generators.

The analysis of the four steam generator scenarios assumes a moderate case using medium values for capacity factor, capital expense, fuel price, and environmental value. As shown in Table 5-10 in Section III in this chapter, the net operating benefit for this case is $109 million 93 NPV. If steam generator replacement is required for operation beyond the end of Fuel Cycle 14, but it is determined not to proceed with replacement, net operating benefits through Fuel Cycle 14 would be -$32 million 93 NPV in the case with all medium values. If steam

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11/ An attainment area meets ambient air quality standards set by local air quality enforcement agencies; a nonattainment area is does not meet such standards.

12/ The detailed and complex analysis of the benefits and costs of replacing the steam generators and extending the Unit's life has not been included in this filing. Such a life extension could warrant BRPU consideration as a deferrable resource at such time steam generator replacement is requested.

generators are replaced without life extension, net operating benefit would be -$18 million 93 NPV; with a 20-year life extension, this same case would show net operating benefits of $224 million 93 NPV. Finally, the increased degradation case would show net operating benefits of $84 million 93 NPV.

II

ANALYSIS

The benefits of SONGS 1 operation were estimated using production simulations of the Edison system with and without SONGS 1, and using the ELFIN production cost model version 1.84 developed by the Environmental Defense Fund. The production cost for the Edison system with SONGS 1 is based on the CEC ER-90 Resource Plan. 13/ The production cost of the Edison system without SONGS 1 was based on the ER-90 Resource Plan developed without SONGS 1 (ER-90 Resource Plan Without SONGS 1) utilizing the ER-90 Resource Plan assumptions and identified cost-effective resource additions in the absence of SONGS 1. The benefits of continued SONGS 1 operation are estimated based on the production cost, capital cost savings, and fossil-fuel emission differences between the ER-90 Resource Plan and ER-90 Resource Plan Without SONGS 1. The benefits and costs were compared using a reference case, a BRPU required case, and 30 alternative sensitivities to indicate the range of cost-effectiveness outcomes of continued SONGS 1 operation.

SONGS 1 benefits were estimated based on operation from the start of Fuel Cycle 12 operation in January 1994 14/ through the end of operation in March 2007. SONGS 1 energy benefits include the value of avoided gas generation, avoided purchased power expense due to operation of the Unit, and O&M expense. SONGS 1 environmental benefits include the value of avoiding residual emissions by the continued operation of the Unit. The SONGS 1 resource deferral or capital cost savings benefit 15/ is the difference in capital costs of future resource additions with and without continued SONGS 1 operation, as determined in the ER-90 Resource Plan and ER-90 Resource Plan Without SONGS 1, respectively, using ICEM. The capital cost of resource additions is based on the resource costs and economic carrying charge rate assumed in the ER-90 Resource Plan. The SONGS 1 residual emission benefits are based on the value of fossil fuel emissions of the gas and purchased power required to replace SONGS 1 generation.

13/ Two small modifications to include more current information on QF contracts have been made to the ER-90. These same adjustments were agreed to by Edison and DRA witnesses in Application No. 90-12-018 (Edison's 1992 GRC).

14/ This date reflects assumed delay in the restart of SONGS 1 from its Fuel Cycle 12 refueling outage, as discussed in Section V.C of Chapter 1.

15/ This represents the capital cost savings of operating SONGS 1. Without SONGS 1, the best alternative resources would require substantial capital investment. This replaces the capacity value benefit described in Exhibit No. SCE-18 to Edison's 1992 GRC application.

III

INPUT PARAMETERS

A. Resource Options

The ER-90 Resource Plan Without SONGS 1 considered the following potential resource options.

Table 5-2

Potential Resource Options
ER-90 Resource Plan 16/

	Net Capacity (MW)	Capacity Cost (1987 $/kW)
Spot Purchases	400	
Liquid Flashed Steam Geothermal	100 (1,200 max)	1,725
Solar Trough	160	1,674
Huntington Beach 3/4 Repower*	385/375	349
Alamitos 1/2 Repower*	407/407	346
Highgrove 3/4 Repower*	136/136	481
San Bernardino Repower*	123/123	365
Etiwanda 1/2 Repower*	78/78	500
Combined Cycle	210	791
Combustion Turbine	145	568

* The addition of repowered capacity is not considered feasible prior to 1996 due to the time required to order equipment, receive licenses and permits, and complete construction.

B. Resource Plans With and Without SONGS 1

Summaries of demand, supply, and future resource additions used in the ER-90 Resource Plan for the Edison planning area are shown in Table 5-3 attached below. The ER-90 Resource Plan would add 2,274 MW of capacity by the year 2003. 17/ The ER-90 Resource Plan Without SONGS 1, shown in Table 5-4, would add 2,374 MW of capacity by the year 2003 18/.

16/ Based on ER-90 assumptions.
17/ Excludes resale cities resource additions of 393 MW.
18/ Excludes resale cities resource additions of 393 MW.

TABLE 5-3

CEC ER-90 Resource Plan

(MW)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2009
Planning Area Peak Demand												
Peak Demand	18410	18932	19422	19924	20439	20972	21469	21993	22482	22969	23412	25875
Exports	294	294	294	196	196	196	196	0	0	0	0	0
Private Supply	494	496	496	516	519	527	533	540	546	553	560	593
Uncommitted DSM	1597	1743	1905	2084	2267	2439	2582	2700	2809	2913	3005	3048
Total Demand	16613	16987	17315	17520	17849	18202	18550	18753	19127	19503	19847	22234
Resources												
Nuclear	2541	2541	2541	2541	2541	2541	2541	2541	2541	2541	2541	2541
Coal	1615	1615	1615	1615	1615	1615	1615	1615	1615	1615	1615	1615
Oil/Gas Steam	8410	8410	8410	8410	8410	8410	8410	8410	8410	8410	8410	8410
Combustion Turbine	580	580	580	580	580	580	580	580	580	580	580	580
Combined Cycle	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012
Hydro	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167
Qualifying Facilities	3431	3448	3594	3587	3587	3587	3587	3587	3587	3587	3587	3587
Firm Purchases	2206	2206	2204	2204	2136	2136	2136	2135	2135	2135	2135	855
Resale Cities	901	886	742	742	742	742	742	719	720	720	720	720
Subtotal	21863	21865	21865	21858	21790	21790	21790	21766	21767	21767	21767	20487
ER-90 Net Resource Additions												
Spot Purchases	400	400	400	400	400	400	400	400	400	400	400	400
Repower	0	0	0	760	760	760	1167	1574	1574	1574	1574	2941
Geothermal	0	0	0	0	0	0	0	200	200	200	300	1200
Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	1260
Other	225	225	347	393	393	393	393	393	393	393	393	393
Subtotal	625	625	747	1553	1553	1553	1960	2567	2567	2567	2667	6194
Total Resources	22488	22490	22612	23411	23343	23343	23750	24333	24334	24334	24434	26681

TABLE 5-4

MODIFIED ER-90 Resource Plan

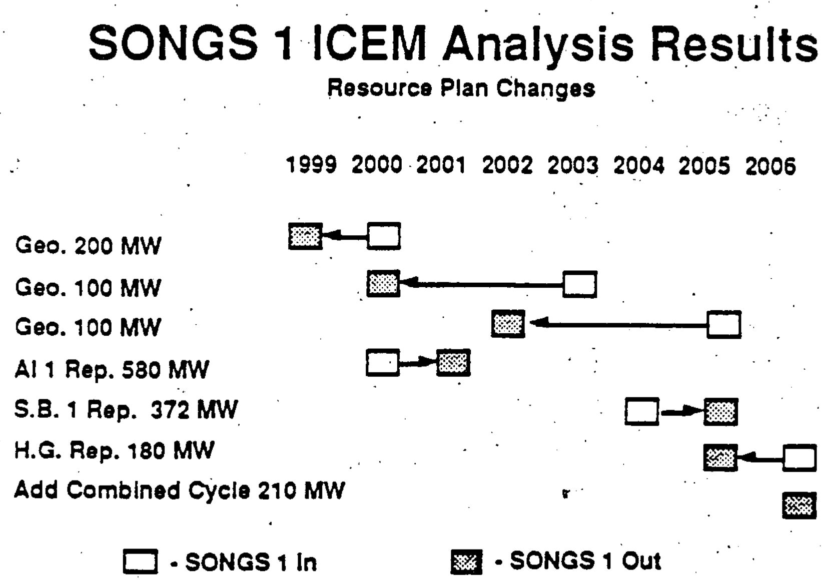
(MW)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2009
Planning Area Peak Demand												
Peak Demand	18410	18932	19422	19924	20439	20972	21469	21993	22482	22969	23412	25875
Exports	294	294	294	196	196	196	196	0	0	0	0	0
Private Supply	494	496	496	516	519	527	533	540	546	553	560	593
Uncommitted DSM	1597	1743	1905	2084	2267	2439	2582	2700	2809	2913	3005	3048
Total Demand	16613	16987	17315	17520	17849	18202	18550	18753	19127	19503	19847	22234
Resources												
Nuclear	2541	2541	2541	2541	2541	2541	2541	2541	2541	2541	2541	2541
Coal	1615	1615	1615	1615	1615	1615	1615	1615	1615	1615	1615	1615
Oil/Gas Steam	8410	8410	8410	8410	8410	8410	8410	8410	8410	8410	8410	8410
Combustion Turbine	580	580	580	580	580	580	580	580	580	580	580	580
Combined Cycle	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012
Hydro	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167	1167
Qualifying Facilities	3431	3448	3594	3587	3587	3587	3587	3587	3587	3587	3587	3587
Firm Purchases	2206	2206	2204	2204	2136	2136	2136	2135	2135	2135	2135	855
Resale Cities	901	886	742	742	742	742	742	719	720	720	720	720
Subtotal	21863	21865	21865	21858	21790	21790	21790	21766	21767	21767	21767	20487
Net Resource Additions												
Spot Purchases	400	400	400	400	400	400	400	400	400	400	400	400
Repower	0	0	0	760	760	760	1167	1574	1574	1574	1574	2941
Geothermal	0	0	0	0	0	0	200	300	300	400	400	1200
Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	1260
Other	225	225	347	393	393	393	393	393	393	393	393	393
Subtotal	625	625	747	1553	1553	1553	2160	2667	2667	2767	2767	6194
Total Resources	22488	22490	22612	23411	23343	23343	23950	24433	24434	24534	24534	26681

The amount of capacity added in the year 2003 varies due to differing ICEM results with ER-90 Resource Plan and ER-90 Resource Plan Without SONGS 1.

The addition of spot purchases and repowering of Huntington Beach 3 and 4 are cost-effective under both resource plan scenarios in the same years. Using ICEM, the ER-90 Resource Plan Without SONGS 1 found 100 to 200 MW geothermal capacity to be cost-effective earlier than in the ER-90 Resource Plan. Furthermore, the addition of the Highgrove repower was found to be cost-effective earlier in the ER-90 Resource Plan Without SONGS 1. On the other hand, the Alamitos and San Bernardino repowers were found to be cost-effective later in the ER-90 Resource Plan Without SONGS 1. The timing and quantity of changes in resource additions in the ER-90 Resource Plan Without SONGS 1 are shown in Figure 5-2.

FIGURE 5-2



C. Operating Benefits

The SONGS 1 operating benefits have three components: (1) production cost (energy) benefit; (2) environmental benefits; and (3) capital cost savings benefit.

1. Energy Benefit

The production cost benefit equals the difference between the fuel, purchased power, and avoided O&M expenses in the ER-90 Resource Plan with SONGS 1 included and in the ER-90 Resource Plan Without SONGS 1. The fuel and purchased power prices are the same in the ER-90 Resource Plan and ER-90 Resource Plan Without SONGS 1.

The production cost benefits include 19/ avoided O&M expense calculated by multiplying the incremental gas generation required without SONGS 1 operating by the Edison system avoided O&M expense of 0.3 cents/kWh in 1993 dollars. This level of avoided O&M cost is also used to calculate QF payments for Edison's avoided gas generation O&M expense.

2. Environmental Benefit

The environmental benefits of SONGS 1 operation are the values of residual emissions avoided by continued SONGS 1 operation. These emissions have been valued in the ER-90 Resource Plan as well as in D.91-06-022, the BRPU Phase 1B decision. Edison's reference case will use the emissions values identified in the ER-90 Resource Plan. Sensitivities will use: (1) the SCAQMD emissions values required by D.91-06-022; and (2) SCAQMD values in-state and Nevada Public Service Commission values out-of-state.

3. Capital Cost Savings Benefit

SONGS 1 capital cost savings benefit is the difference between the incremental cost of the resource plan changes in the ER-90 Resource Plan and the ER-90 Resource Plan Without SONGS 1. Since the SONGS 1 operation was assumed to end in March 2007, capital costs were annualized with an economic carrying charge rate to compare SONGS 1 with resources having lives extending beyond 2007.

Annualizing capital costs with an economic carrying charge rate provides a nominal annual value for the capital cost of a resource in a specific year. The annualized capital costs are equivalent to the present worth savings of deferring the capital expenditure stream for a year or more. A more intuitive way to describe the annualized capital costs is as the cost of "renting" the resource for one year.

19/ SONGS 1 generation is primarily replaced by gas generation. Increased gas generation due to the absence of SONGS 1 results in increased O&M expenses associated with operating the gas generating units. Avoiding these O&M expenses is a benefit of continued SONGS 1 operation.

The annualized capital costs allow the cost of operation of each resource addition to be calculated in each year the resource is used. Thus, the benefits of deferring a resource by one or more years can be calculated, as well as the benefits of permanent deferral of a resource, even though the analysis is only through March 2007.

Calculating the capital costs of resource additions beyond March 2007 is unnecessary because the only capital cost savings benefit considered in this analysis are associated with "renting" alternative resources when SONGS 1 would have been operating. All values are then converted to a 1993 present worth so that capital cost savings benefit, production cost benefit, O&M expense, environmental benefits, and any other benefits or costs can be compared on an identical basis.

Figure 5-2 demonstrates how operating dates of resource additions change when SONGS 1 is removed from the ER-90 Resource Plan. For example, without SONGS 1 a 200 MW geothermal addition was advanced from a 2000 operating to a 1999 operating date. Based on the changed operating dates shown in Figure 5-2, the capital cost savings benefit from the SONGS 1 continued operation in the reference case is $112 million 93 NPV.

The values chosen for the economic carrying charge rate, discount rate, and capital costs for the specific technologies considered in Edison's analysis are those used by the CEC in the ER-90 Resource Plan.

D. Costs

The costs of continued SONGS 1 operation include nuclear fuel, incremental O&M expense, refueling expense, and capital costs, as discussed in Chapters 3 and 4.

E. Sensitivities

This cost-effectiveness analysis considered sensitivities regarding capacity factor, gas price, environmental benefits, and capital cost. The sensitivity values are shown in Table 5-5 below.

Table 5-5

Sensitivity Values Used
In SONGS 1 Cost-Effectiveness Analysis

Capacity Factor
- High = 80%
- Medium = 70%
- Low = 60%

Capital Cost ($1993 Present Worth, Revenue Requirement Edison Share)
- High = 271
- Medium = 233
- Low = 208

Fuel Cost
- High = CEC Fuel ($7.09/MMBtu in 2000)
- Medium = SoCal 90 ($5.56/MMBtu in 2000)
- Low = 5% growth after 1995 ($3.06/MMBtu in 2000)

Emissions Values
- High = SCAQMD in-state, SCAQMD out-of-state
- Medium = SCAQMD in-state, Nevada out-of-state

Emission Values (1990 $/ton)

Pollutant	CEC In-State	CEC Out-of-State	SCAQMD	Nevada
NOx	18,956	4,412	28,362	6,800
SOx	18,792	1,634	21,185	1,560
PM-10	12,746	1,307	6,135	4,180
ROG	5,393	490	20,258	--
Cx	30	30	--	22*

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* Although the Nevada Public Service Commission adopted a CO_2 value smaller than the CEC's, consistent with D.91-06-022, the CEC's value will be used for all areas.

1. Alternative Capacity Factors

As discussed in Chapter 1, following completion of the remaining modifications required for issuance by the NRC of the FTOL for SONGS 1, the Unit should operate at an average capacity factor of 70 percent over the period 1994-2007. A range of capacity factor performance reflecting industry experience has been considered, with 60 percent the low value and 80 percent the high value.

2. Alternative Fuel Price Forecasts

Three alternative fuel price forecasts have been considered in the analysis of possible SONGS 1 cost-effectiveness outcomes. The alternative fuel prices are:

a. CEC Fuel Price

In its 1989 Biennial Fuels Report (BFR), the CEC adopted a forecast of natural gas prices which was subsequently used in the development of ER-90. Natural gas prices today are lower than those forecast in the 1989 BFR for 1991. These gas prices are forecast to escalate at about 8% annually. As such, Edison believes that the CEC ER-90 fuel prices represent the upper end of the range of likely gas price outcomes. They are therefore used as a high gas price forecast in the sensitivity analysis.

b. SoCal 1990

The Southern California Gas Company published its most recent forecast in the 1990 California Gas Report. This forecast falls in the middle of the range of likely gas price outcomes. This is represented as the medium gas price in the sensitivity analysis.

c. Low Gas Prices

It may be possible for a lower gas price than those previously listed to be realized. Therefore, a low gas forecast that includes no escalation before 1995 and 5 percent per year thereafter has been developed for the purpose of this analysis. This results in an average real annual growth rate from present to 2007 of about -1.5%, and represents a lower bound of reasonable gas prices for the future.

The three alternative gas price forecasts are shown in Table 5-6 below, and Figure 5-3.

Table 5-6

Gas Price Forecasts ($/MMBtu)

Year	CEC (1)	SoCal 90 (2)	Low (3)
1994	4.57	3.74	2.60
1995	4.89	3.98	2.60
1996	5.30	4.20	2.60
1997	5.70	4.47	2.65
1998	6.13	4.79	2.78
1999	6.58	5.19	2.92
2000	7.09	5.56	3.06
2001	7.62	5.99	3.22
2002	8.16	6.49	3.38
2003	8.86	7.02	3.55
2004	9.62	7.62	3.72
2005	10.42	8.25	3.91
2006	11.32	8.92	4.12
2007	12.28	9.64	4.35

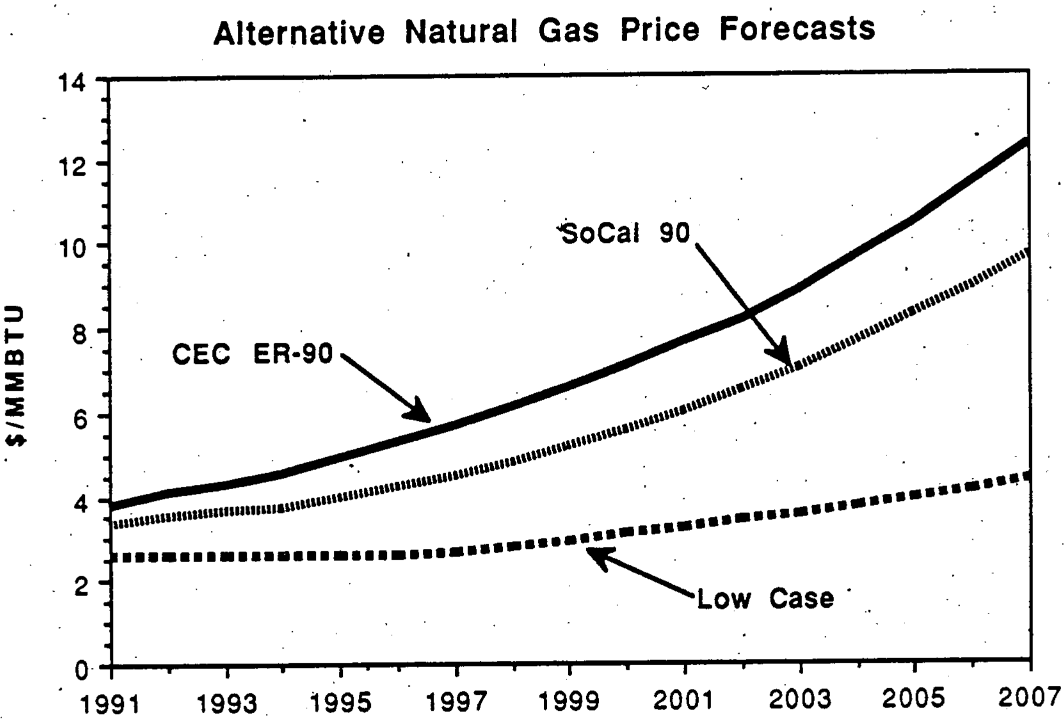
3. Alternative Environmental Values

Much attention has been focused lately on the quantified value associated with avoiding residual emissions. The CEC adopted values for use in the ER-90 Resource Plan, and these values were used in this analysis for the development of the ER-90 Resource Plan with SONGS 1 and the ER-90 Resource Plan without SONGS 1. D.91-06-022 adopted a different set of values based on the costs of controlling emissions estimated by the SCAQMD. While Edison has testified that it believes the use of SCAQMD values for out-of-state emissions is inappropriate, D.91-06-022 orders that these be used in the BRPU Compliance Phase. Edison has used these values as the high environmental case. D.91-06-022 also allows sensitivities to be evaluated using the SCAQMD values in nonattainment areas, and Nevada Public Service Commission's values for attainment areas. Since Edison's in-state air basins are all in nonattainment areas, and out-of-state purchases are generally made from attainment areas, the SCAQMD values were used for in-state emissions as defined in the CEC ER-90, and Nevada Public Service Commission values were used for out-of-state emissions as the medium emission sensitivity. These alternative values were shown in Table 5-5.

4. Alternative Capital Costs

As discussed in Section II of Chapter 3, a range of future capital expenditures has also been established for evaluation of cost-effectiveness sensitivities.

FIGURE 5-3


Alternative Natural Gas Price Forecasts
$/MMBTU
14
12
10
8
6
4
2
0
1991
1993
1995
1997
1999
2001
2003
2005
2007
SoCal 90
CEC ER-90
Low Case

F. Steam Generator Scenarios

Four alternative scenarios were analyzed based on assumptions consistent with medium levels of the variables identified in the sensitivity analysis. These four scenarios consist of: (1) shutdown when replacement of steam generators is assumed to be required; (2) replacement of steam generators without extension of the Unit's life beyond March 2007; (3) replacement of steam generators with a 20-year life extension; and (4) operation to March 2007 with increased degradation of Unit capacity due to accelerated steam generator tube corrosion.

G. Other Analytical Input Parameters

To implement this analysis, a number of financial input parameters are required to perform the necessary numerical calculations. These parameters are discussed in detail below.

1. Financial

a. Discount Rate

A rate equal to Edison's incremental cost of capital is used to calculate the present value of future costs and benefits associated with prospective incremental investments when making capital budgeting decisions. For Edison, this rate is 12 percent and is computed as a mathematical weighted average of the cost of debt and preferred and common equity.

b. Escalation Rates

The O&M escalation rates used in the cost-effectiveness model are shown in Table 5-7.

TABLE 5-7

ESCALATION RATES PERTINENT TO SONGS 1

The escalation rates used in the evaluation of SONGS 1 are shown below. They are based on annual analyses performed by Edison. Such rates are used throughout the Company in developing budgets and projecting other future expenditures. The United States inflation rate serves as a basis for the assumptions underlying these rates. Several common measures of inflation rates, including the GNP Implicit Price Deflator, the Consumer Price Index, the Producer Price Index and specific regional indicators are used as sources in preparing the long-range escalation projections. The escalation rates shown for any year represent the rate of increase over the previous year.

Year	O&M	Capital
1991	3.7	4.0
1992	4.1	5.0
1993	3.7	5.0
1994	3.9	5.0
1995	4.0	5.0
1996-2000	4.5	5.0
2001-Beyond	4.9	5.0

c. Payroll Taxes and A&G Expense

The Payroll Taxes and A&G expense for Edison used in this evaluation were derived from the 1992 Test Year O&M data submitted herewith. These expenses were equal to 31.3 percent of annual O&M expense and refueling cost. The detailed development of this percentage is shown in Table 5-8. Payroll taxes and A&G expense were assumed to escalate at the O&M rate shown in Table 5-8. In the event of a premature shutdown of SONGS 1, the SONGS 1 A&G expense was assumed to continue at a level equal to 65 percent of its forecast level under full operation.

TABLE 5-8

SONGS 1 COST-EFFECTIVENESS STUDY
PAYROLL TAX/A&G EXPENSE RATE WORK SHEET

This work sheet develops a percentage that can be applied to total O&M and refueling costs for SONGS 1 in order to properly assess Payroll Taxes and A&G Expenses on operating costs. This percentage is assumed to remain constant over the remaining life of SONGS 1.

Using data consistent with the Edison 1992 General Rate Case Test Year:

SONGS 1 Direct Edison Labor	$39,766,000
SONGS 1 Refueling Direct Edison Labor	3,044,000
Total SONGS 1 Edison Direct Labor	$42,810,000
SONGS 1 Total O&M and Refueling Cost	$83,600,000

Payroll Tax and A&G Expense (Normal Operation):

Cost = (A&G Expense Rate + Pensions & Benefits) (Total SONGS 1 Direct Edison Labor)
+ (Payroll Tax Rate + Worker's Compensation) (Total SONGS 1 Direct Edison Labor)
+ (1%) (Total SONGS 1 Non-Labor Cost)

Cost = (0.2884 + 0.2321 + 0.0701 + 0.011) ($42,810,000) + (0.01) ($40,790,000)
Cost = $26,162,000

Model % = (Payroll Tax and A&G Expense Cost)/(SONGS 1 Total O&M and Refueling Cost)
Model % = ($26,162,000)/($83,600,000)

Model % = 31.3%

<u>A&G Expense (Shutdown)</u>: Based on the methodology used in A.85-05-008 for Fuel Cycles 9, 10, and 11, the A&G expense in the shutdown mode was assumed to be 65 percent of the A&G expense in the normal operating mode. This same assumption has been used in calculating shutdown payroll tax and A&G expense in the post-Fuel Cycle 11 analysis.

d. Revenue Requirement of Capital Investment

The revenue requirement of Capital Investment is the present value of capital requirements multiplied by the revenue requirement factor. The revenue requirement factor represents the relationship between capital expenditures and the present value of subsequent capital-related revenue requirements associated with those expenditures. The values of these factors are shown in Table 5-9.

TABLE 5-9

CAPITAL REVENUE REQUIREMENT FACTORS

Year (1)	Factor (2)
1994	1.37
1995	1.37
1996	1.36
1997	1.36
1998	1.36
1999	1.35
2000	1.35
2001	1.34
2002	1.33
2003	1.32
2004	1.30
2005	1.28
2006	1.25

2. Technical

a. Decommissioning Expense

Funds adequate for eventual decommissioning of SONGS 1 are being collected in rates. Current plans have SONGS 1 being placed in safe storage in 2007 and decommissioned with SONGS 2 and 3 in 2014. The mothballing of SONGS 1 in preparation for decommissioning would occur in 2007 for all cases considered in this analysis. The current collection schedule anticipates fully funding decommissioning the Unit by 2004. Any early collection of the funds has no effect on the cost-effectiveness analysis since money collected through 2004 should be sufficient to cover expenses beginning in the now planned 2007 shutdown time frame. Any overcollection of funds due to the fact that fewer years of mothballing are then required (since shutdown occurs three years later than originally planned) will be addressed through the normal General Rate Case process for determining decommissioning collections. Therefore, decommissioning costs have been excluded from the cost effectiveness analysis.

b. SONGS 1 Capacity Rating

The net capacity rating of SONGS 1 (Edison 80% share) used in the cost-effectiveness analysis is 304 megawatts (MW) for Fuel Cycle 12 and 324 MW thereafter, including the HP turbine Modification to be implemented in Fuel Cycle 13.

IV

RESULTS

The sensitivities and scenarios analyzed by Edison fall into four general categories: (1) reference case; (2) BRPU required case; (3) 30 sensitivities (shown in Figure 5-1); and (4) four steam generator condition scenarios. Table 5-10 shows the results for the reference case and the BRPU required case. Table 5-11 shows the results for each of the 30 sensitivities analyzed. Finally, Table 5-12 shows the results for the steam generator condition scenarios. All values are shown as 93 NPV operating benefits in millions of dollars associated with Edison's 80 percent share of SONGS 1.

A. Reference Case

The reference case uses the ER-90 Resource Plan assumptions regarding fuel prices and emission values. A 70 percent capacity factor and medium capital costs were assumed for this case. The reference case shows $177 million 93 NPV operating benefits. This estimate is based on Edison's 80 percent share of costs and benefits. This case includes $152 million 93 NPV of environmental benefit based on environmental values from the ER-90 Resource Plan using the CEC values for residual emissions.

B. BRPU Required Case

BRPU requires that all existing units be analyzed based on five-year average of unit performance. The BRPU required case uses a five-year historical average of the SONGS 1 capacity factor of 44 percent. This sensitivity is required by D.86-07-004, 20/ in OIR-2, the predecessor proceeding to BRPU. However, as this historical period reflects the impact of extended outages to perform modifications due to change in NRC requirements, 44 percent is inappropriate to evaluate the Unit's performance in a future operating period following completion of these required modifications. Consequently, this is not a realistic forecast of SONGS 1 post-Fuel Cycle 11 performance.

The BRPU required case was analyzed using CEC fuel prices, SCAQMD environmental values, and medium capital costs. The net operating benefit in this case was $63 million 93 NPV, including $244 million NPV in environmental benefit. The reference case results and BRPU required case results are shown in Table 5-10.

20/ D.86-07-004, pp. 52 and 86.

TABLE 5-10

SOUTHERN CALIFORNIA EDISON COMPANY

SONGS 1 COST-EFFECTIVENESS RESULTS

REFERENCE AND BRPU REQUIRED CASES

Millions of Dollars, 1993 Net Present Value, Edison 80% Share

Line No.	Description	Production Benefits (1)	Capital Cost Savings Benefits (2)	Environmental Benefits (3)	SONGS 1 Expenses (4)	Capital Requirements (5)	Net Operation Benefits (6)
1.	Reference Case	655	112	152	509	233	177
2.	BRPU Required Case	384	112	244	444	233	63

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TABLE 5-11

SONGS 1 Cost-Effectiveness Sensitivities

($MM 1993 Present Value)

Case	Capacity Factor	Capital Cost	Gas Price	Environmental Value	Production Benefits	Capital Benefits	Environmental Benefits	SONGS 1 Expenses	Capital Requirements	Net Operating Benefits
1	60%	High	CEC	AQMD	557	112	362	480	271	280
2	60%	High	CEC	AQMD/Nev	557	112	168	480	271	86
3	60%	High	SoCal 90	AQMD	462	112	362	480	271	185
4	60%	High	SoCal 90	AQMD/Nev	462	112	168	480	271	-9
5	60%	High	Low	AQMD	305	112	362	480	271	28
6	60%	High	Low	AQMD/Nev	305	112	168	480	271	-166
7	70%	High	CEC	AQMD	655	112	421	509	271	408
8	70%	High	CEC	AQMD/Nev	655	112	196	509	271	183
9	70%	High	SoCal 90	AQMD	543	112	421	509	271	296
10	70%	High	SoCal 90	AQMD/Nev	543	112	196	509	271	71
11	70%	High	Low	AQMD	359	112	421	509	271	112
12	70%	High	Low	AQMD/Nev	359	112	196	509	271	-113
13	70%	Med	CEC	AQMD	655	112	421	509	233	446
14	70%	Med	CEC	AQMD/Nev	655	112	196	509	233	221
15	70%	Med	SoCal 90	AQMD	543	112	421	509	233	334
16	70%	Med	SoCal 90	AQMD/Nev	543	112	196	509	233	109
17	70%	Med	Low	AQMD	359	112	421	509	233	150
18	70%	Med	Low	AQMD/Nev	359	112	196	509	233	-75
19	80%	Med	CEC	AQMD	762	112	504	538	233	607
20	80%	Med	CEC	AQMD/Nev	762	112	235	538	233	338
21	80%	Med	SoCal 90	AQMD	632	112	504	538	233	477
22	80%	Med	SoCal 90	AQMD/Nev	632	112	235	538	233	208
23	80%	Med	Low	AQMD	419	112	504	538	233	264
24	80%	Med	Low	AQMD/Nev	419	112	235	538	233	-5
25	80%	Low	CEC	AQMD	762	112	504	538	208	632
26	80%	Low	CEC	AQMD/Nev	762	112	235	538	208	363
27	80%	Low	SoCal 90	AQMD	632	112	504	538	208	502
28	80%	Low	SoCal 90	AQMD/Nev	632	112	235	538	208	233
29	80%	Low	Low	AQMD	419	112	504	538	208	289
30	80%	Low	Low	AQMD/Nev	419	112	235	538	208	20

TABLE 5-12

SOUTHERN CALIFORNIA EDISON COMPANY

SONGS 1 COST EFFECTIVENESS RESULTS

STEAM GENERATOR SCENARIOS

Millions of Dollars, 1993 Net Present Value, Edison 80% Share

Line No.	Description	Production Benefits (1)	Capital Benefits (2)	Environmental Benefits (3)	SONGS 1 Expenses (4)	Capital Requirements (5)	Net Operation Benefits (6)
1.	Case A	286	19	136	289	184	-32
2.	Case B	551	112	197	509	369	-18
3.	Case C -						
4.	Benefits Total =	1,653			915	514	224
5.	Case D	523	112	191	509	233	84

Case A: Shutdown case.
Case B: Steam generator replacement without life extension.
Case C: Steam generator replacement with life extension.
Case D: Degradation case.

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C. Reasonable Combinations of Alternative Assumptions

All reasonable combinations of the alternative capacity factors, capital costs, gas fuel costs, and environmental values are described in Table 5-11. These 30 sensitivities are shown in Figure 5-1. Some combinations of capital costs and capacity factor were inconsistent and therefore were not analyzed. For example, a combination involving both low capacity factor and low capital cost was not included because either the low capacity factor would result from extensive modifications, as during the past decade, or investment would be made in response to the low capacity factor to correct whatever condition was preventing improved performance over such a long period.

The 30 sensitivities show a range of net operating benefits from -$166 million to +$632 million 93 NPV. Generally, SONGS 1 was not cost-effective only when both fuel price was low and environmental value was medium. SONGS 1 was usually found to be moderately cost-effective ($0-200 million 93 NPV) with: (1) medium fuel prices and medium emissions values, or (2) high emissions value and low fuel prices. SONGS 1 was generally highly cost-effective ($200-$600 million NPV) with high emissions values and medium or high fuel prices.

Net operating benefits range from $-166 million 93 NPV to +$632 million 93 NPV for a total range of $798 million 93 NPV. The variation in results is primarily due to fuel prices and environmental value. For example, at 70 percent capacity factor, energy benefits vary by $296 million 93 NPV due to fuel prices, and environmental benefits vary by $225 million 93 NPV. The $225 million 93 NPV increased benefit in the high environmental case is due only to the valuation of out-of-state emissions using SCAQMD residual emissions values instead of Nevada Public Service Commission values. Edison does not believe using SCAQMD values for out-of-state emissions is appropriate.

Capacity factor variations result in a change in energy benefits of $80 to $90 million NPV for each 10 percent change in capacity factor at SoCal Gas prices. Capital cost savings benefits depend only on the changes in the resource plan with and without SONGS 1. Since these alternative resource plans were determined using a single set of assumptions, ER-90, there is no variation in capital cost savings benefit. This benefit is $112 million 93 NPV for all sensitivities.

D. Steam Generators Scenarios

The final category of scenarios considers potential unanticipated accelerated corrosion of steam generator tubes. The cases include: (1) early shutdown; (2) steam generator replacement without life extension; (3) replacement with a 20-year life extension; and (4) accelerated capacity degradation. Both the shutdown case (1) and the steam generator replacement without life extension case (2) were not found cost-effective. Net operating benefits, as shown in Table 5-12, were -$32 million and -$18 million 93 NPV, respectively, for these two cases. An analysis of the life extension scenario (3) assumed $136 million 93 NPV in capital cost for steam generators and a 20-year life extension yielding a net operating benefit of $224 million 93 NPV. The steam generator replacement was assumed to restore the Unit's rated capacity to 436 MW (349 MW for Edison) starting in Fuel Cycle 15, and results were scaled up to estimate benefits through March 2007 at 436 MW (349 MW for Edison). 21/ Beyond March 2007, an extrapolation was used. The steam generator tube degradation case (4) assumed a 5 MW per fuel cycle reduction in the Unit's operating capability (Edison's share). In this case, benefits were scaled down to estimate the net benefit of this scenario. SONGS 1 was found to provide $84 million 93 NPV operating benefits in this case.

V

CONCLUSION

SONGS 1 provides fuel diversity, energy benefits, capital cost savings benefits, and environmental benefits to the Edison system. Although the range of benefits varies, under most sets of reasonable assumptions, the benefits outweigh all capital, fuel, and O&M expenses associated with continued SONGS 1 operation. Positive net operating benefits from this analysis indicate that continued SONGS 1 operation is a lower cost option than the best alternatives identified using ICEM and the CEC's ER-90 Resource Plan.

21/ Estimates were developed by multiplying the energy and environmental benefits by the ratio of new to old unit capability (349/324).

APPENDIX A

NUCLEAR REGULATORY COMMISSION

FTOL ORDER

DATED JANUARY 2, 1990

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON D. C. 20555

January 2, 1990

RECEIVEL
JAN 08 1990
NUCLEAR LICENSING

Docket No. 50-206

Mr. Harold B. Ray
Vice President
Southern California Edison Company
Irvine Operations Center
23 Parker Street
Irvine, California 92718

Dear Mr. Ray:

SUBJECT: ORDER CONFIRMING LICENSEE COMMITMENTS ON FULL-TERM OPERATING LICENSE OPEN ITEMS - SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 1 (TAC NO. 11232)

The Commission has issued the enclosed order confirming your commitment to implement the full-term operating license open items set forth in your letter of October 2, 1989, for which the NRC staff requested completion in the next two refueling outages.

The order references your letter and, in its attachments, contains lists of the open items that are required to be implemented in accordance with the schedules provided in your letter.

In confirming your schedules, this order modifies the Commission's previous order dated May 10, 1989, to now require that the reactor vessel level indication system be installed during the cycle 12 refueling outage instead of the cycle 11 refueling outage, as described in your letter. Also consistent with your schedules, the order confirms your request to conduct the upcoming steam generator tube inspection during the cycle 11 refueling outage commencing June 30, 1990, rather than by March 7, 1990.

A copy of this order is being filed with the Office of the Federal Register for publication.

Sincerely,

George W. Knighton

George W. Knighton, Director
Project Directorate V
Division of Reactor Projects - III,
IV, V and Special Projects
Office of Nuclear Reactor Regulation

Enclosure:
Order

cc: w/enclosure
See next page

Mr. Harold B. Ray
Southern California Edison Company

San Onofre Nuclear Generating
Station, Unit No. 1

cc
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Mrs. Betty Geismar
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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	Docket No. 50-206
SOUTHERN CALIFORNIA EDISON COMPANY	)	License No. DPR-13
SAN DIEGO GAS AND ELECTRIC COMPANY	)	
San Onofre Nuclear Generating Station, Unit No. 1	)	

ORDER CONFIRMING LICENSEE COMMITMENTS ON FULL-TERM OPERATING LICENSE OPEN ITEMS

I.

Southern California Edison Company and San Diego Gas and Electric Company (the licensees) are the holders of Provisional Operating License No. DPR-13, which authorizes the licensees to operate San Onofre Nuclear Generating Station, Unit 1, at power levels up to 1347 megawatts thermal (rated power). The facility is a pressurized water reactor located on the licensees' site in San Diego County, California. The license is subject to all applicable provisions of the rules, regulations, and orders of the U.S. Nuclear Regulatory Commission (NRC).

II.

On May 1, 1989, the NRC staff met with the licensees to discuss the NRC requirements for conversion of Provisional Operating License No. DPR-13 to a full-term operating license and additional actions needed to resolve NRC concerns with respect to broken bolts on the reactor vessel thermal shield. The NRC staff explained that, for a variety of reasons, certain safety-significant improvements due to be made to the facility had been unacceptably delayed over the years and that a firm, integrated schedule must be developed to complete these actions in the next two refueling outages. These actions consist of Three Mile Island Action Plan items, NRC generic letter items, and action items resulting from the integrated plant safety assessment for San Onofre Unit 1 (NUREG-0829). Collectively, these actions are referred to as the full-term operating license (FTOL) open items and are identified in Attachments 1 and 2. They are so called because their implementation is considered a prerequisite to conversion of Provisional Operating License No. DPR-13 to an FTOL.

The licensees were requested to finalize and document the schedules discussed at the meeting in a letter to the NRC, and to include their rationale for the schedules.

With respect to the thermal shield, the licensees proposed a mid-cycle inspection by not later than June 30, 1990, and a vibration monitoring and action plan to resolve the staff's concerns. These commitments were subsequently confirmed in Amendment No. 127 issued on May 15, 1989.

The schedular request pertaining to the FTOL open items was subsequently confirmed in an NRC letter to licensees dated August 17, 1989, which reiterated the NRC staff's desire to have the FTOL open items completed in the next two refueling outages, even if the outages had to be extended in order to finish them. The letter stated that the NRC staff understood that its request did involve significant commitments that would require some time for evaluation, but requested the licensees to give the matter priority and to respond by the end of September 1989.

III.

On October 2, 1989, the licensees responded with an integrated schedule (shown in Attachments 1 and 2) for accomplishing the FTOL open items in the next two refueling outages. The plan calls for completing or resolving 18 open items in the next refueling outage (fuel cycle 11) and 21 open items in the second refueling outage (fuel cycle 12) - a total of 39 items. The schedule shows significant improvements in both scheduling and activity. The reactor vessel thermal shield would be repaired in the outage beginning June 30, 1990, rather than inspected and repair deferred until September 1991. Also, the licensees, having determined that significant safety improvement will be achieved by upgrading the recirculation portion of the safety injection system as well as the injection portion, have included these improvements in the schedule for the cycle 12 outage. The licensees also have committed to install a plant-specific reference simulator for operator training. Taken as a whole, the licensees have made significant commitments that involve substantial safety improvements to the facility and that are responsive to the NRC staff's request.

To support this schedule as proposed, the licensees propose to combine the fuel cycle 11 refueling with repair of the thermal shield and inspection of the steam generator tubes in one extended outage (June 30, 1990, to about December 2, 1990) (Attachment 3).

The licensees are currently required to install a reactor vessel level indicating system and upgrade the core exit thermocouples by not later than startup for fuel cycle 11 in response to TMI Action Plan Item II.F.2, "Inadequate Core Cooling Instrumentation" (NRC order dated May 10, 1989). Because the fuel cycle 11 refueling would start much earlier than previously scheduled (June 30, 1990, rather than September 17, 1991), the licensees do not have sufficient time to design and test a reactor vessel level monitor because existing designs must be modified for installation at San Onofre Unit 1 (licensees' amendment request dated November 1, 1989). The licensees propose to install the reactor vessel level monitor and upgrade the core exit thermocouples at the same time by not later than fuel cycle 12, and submit specific implementation plans by December 1, 1990. This would entail a relatively minor change in schedule that would involve an additional 9 months of plant operation before implementation and is acceptable.

The second schedular change involves the inspection schedule for the steam generator tubes which would be required to be inspected by March 7, 1990 (licensees' amendment request dated October 31, 1989). The licensees request that this inspection be coordinated with the long outage beginning June 30, 1990. This revised schedule for inspection is acceptable, since the licensees have shown that steam generator tube corrosion has stabilized, and this is a relatively modest 4-month extension of a 24-month inspection interval.

IV.

I find that the licensees' commitments collectively represent significant safety improvements to the facility and are acceptable. In view of the foregoing, I have determined that the public health and safety require that the licensees' commitments contained in their letter of October 2, 1989, be confirmed by order.

Accordingly, pursuant to Sections 103, 161b and 161i of the Atomic Energy Act of 1954, as amended, and the Commission's regulations in 10 CFR 2.204 and 10 CFR Part 50, IT IS HEREBY ORDERED that Provisional Operating License No. DPR-13 be modified as follows:

Licensees shall implement the schedular commitments contained in their letter of October 2, 1989, as summarized in Attachments 1, 2, and 3 hereto with respect to the specific activities to be conducted at outages for fuel cycles 11 and 12 (exact dates of the outages may be revised from time to time). Specific plans for implementation of Item II.F.2, "Inadequate Core Cooling Instrumentation System" (Generic Letter 82-28), shall be submitted to the NRC for approval by no later than December 1, 1990.

The licensees or any person who has an interest adversely affected by this order may request a hearing within 30 days of the date of publication of this order in the FEDERAL REGISTER. A request for hearing must be addressed to the Director, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with copies to the Assistant General Counsel for Enforcement at the same address. If a person other than the licensees requests a hearing, that person shall set forth with particularity the manner in which the petitioner's interest is adversely affected by this order and should address the criteria set forth in 10 CFR 2.714(d).

If a hearing is requested, the Commission will issue an order designating the time and place of the hearing. If a hearing is held, the issue to be considered shall be whether this order should be sustained. Upon the failure to answer or request a hearing within the specified time, this order shall be final without further proceedings.

FOR THE NUCLEAR REGULATORY COMMISSION

Thomas E. Murley

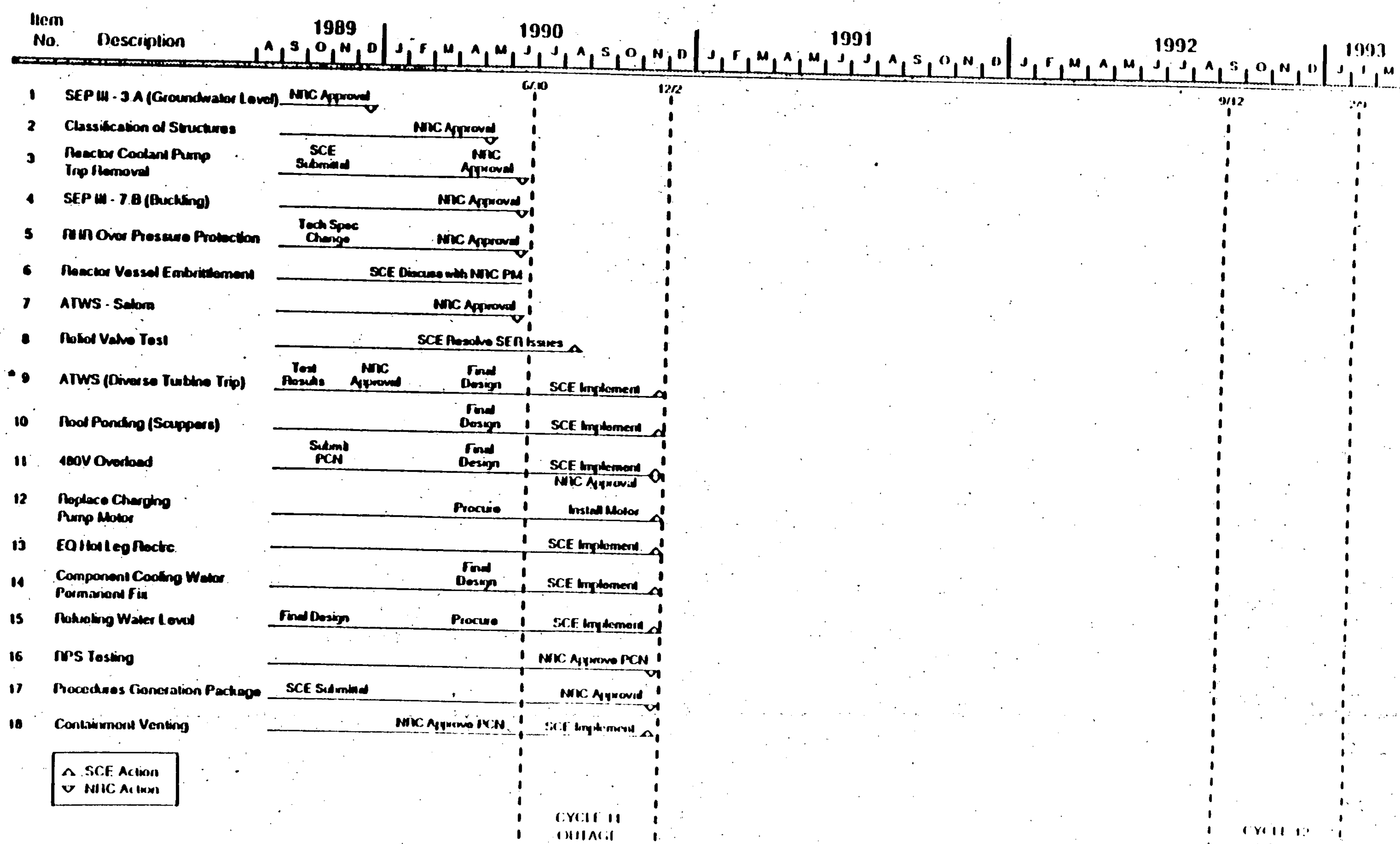
Thomas E. Murley, Director
Office of Nuclear Reactor Regulation

Dated at Rockville, Maryland
this 2nd day of January, 1990

Attachments:
1. SONGS 1 Cycle 11 FTOL Projects
2. SONGS 1 Cycle 12 FTOL Projects
3. SONGS 1 Operation Schedule

ATTACHMENT 1

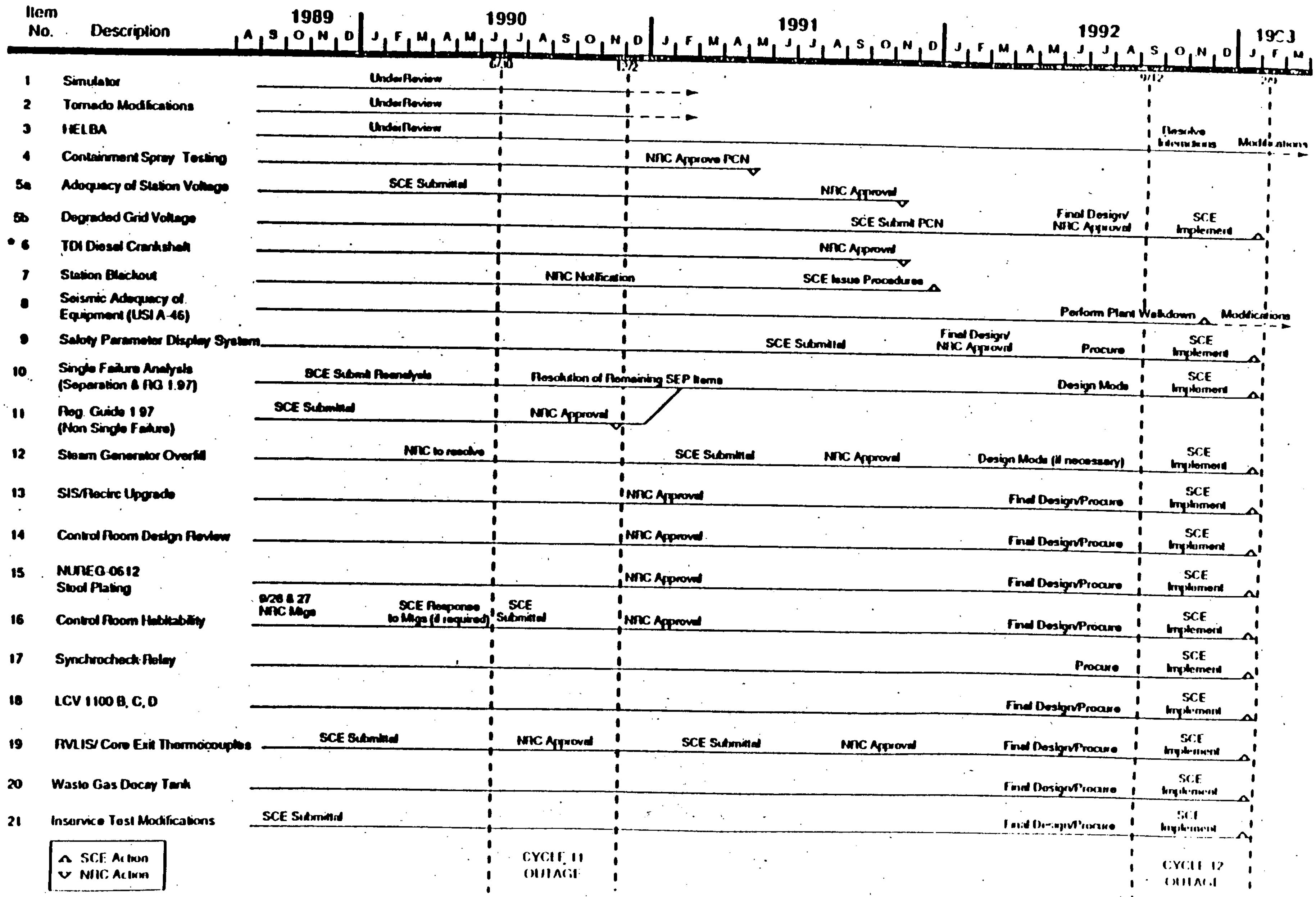
SONGS 1 Cycle 11 FTOL Projects



* Critical NRC action required

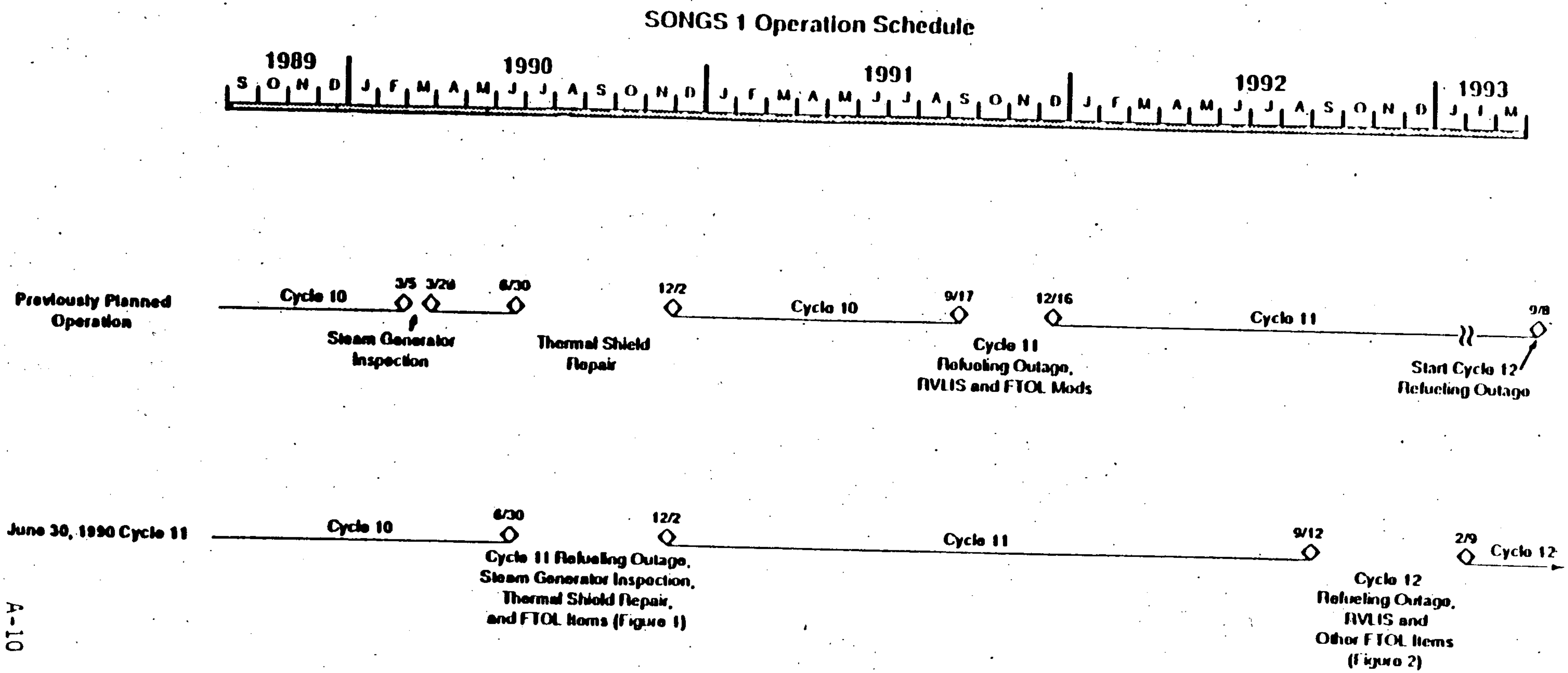
ATTACHMENT 2

SONGS 1 Cycle 12 FTOL Projects



* Critical NRC action required

ATTACHMENT 3



APPENDIX B

JANUARY 2, 1990 - ORDER ITEMS

APPENDIX B

January 2, 1990 ORDER ITEMS

Item	Description	Source or Requirement	Completion
11.1	Effect of High Water Level on Structures (Ground Water Level)	SEP III-3.A	Fuel Cycle 11
11.2	Seismic and Quality Classification of Structures	SEP III-1	Fuel Cycle 11
11.3	Reactor Coolant Pump Trip Removal	TMI II.K.3.5	Fuel Cycle 11
11.4	Buckling Stress Analysis of Containment	SEP III-7.B	Fuel Cycle 11
11.5	Residual Heat Removal System Overpressure Protection	SEP V-11.B	Fuel Cycle 11
11.6	Reactor Vessel Support Embrittlement	GSI-15, FTOL Order	Fuel Cycle 11
11.7	Impact of Salem Reactor Trip System Failure (Salem ATWS)	GSI-75, GL 83-28	Complete
11.8	Reactor Coolant System Relief Valve Test	TMI II.D.1	Complete
11.9	Diverse Turbine Trip In Response to Postulated Failure of Reactor Trip (ATWS)	USI A-9, 10 CFR 50.62	Complete
11.10	Roof Ponding Due to Maximum Expected Rainfall (Scuppers)	SEP III-3.A, II-3.B	Complete
11.11	Potential 480V Electrical Overload System During Postulated Accidents	Safety Enhancement	Complete
11.12	Replace Charging Pump Motor With Larger Qualified Model	USI A-24, 10 CFR 50.49	Complete

APPENDIX B

January 2, 1990 ORDER ITEMS
(Continued)

Item	Description	Source or Requirement	Completion
11.13	Environmental Qualification (EQ) of Safety Injection System Hot Leg Recirc Valves	Safety Enhancement	Complete
11.14	Component Cooling Water System Upgrade	Safety Enhancement	Complete
11.15	Refueling Water Level Indicating System	GL 88-17	Complete
11.16	Reactor Protection System Testing	SEP VI-10.A	Fuel Cycle II
11.17	Upgrading of Plant Accident Procedures	TMI I.C.1	Complete
11.18	Containment Venting	Multiplant Action Item (MPA-B-24)	Fuel Cycle 11
12.1	Simulator	Rule, 10 CFR 55.45	Fuel Cycle 12
12.2	Tornado Modifications	SEP III-2, III-4.A	Fuel Cycle 12
12.3	High Energy Line Break Analysis (HELBA)	SEP III-5A, III-5B, VII-3	Fuel Cycle 12
12.4	Containment Spray Testing	SEP VI-10.A	Fuel Cycle 12
12.5a	Adequacy of Station Electrical Voltage	SEP VIII-1.A	Fuel Cycle 12
12.5b	Degraded (Lowered) Grid Voltage	SEP VIII-1.A	Fuel Cycle 12
12.6	TDI Diesel Crankshaft Technical Specification Change	GSI-91, NUREG-1216	Complete
12.7	Loss of Site AC Power (Station Blackout) Evaluation	Rule, 10 CFR 50.63	Fuel Cycle 12

APPENDIX B

January 2, 1990 ORDER ITEMS
(Continued)

Item	Description	Source or Requirement	Completion
12.8	Seismic Adequacy of Equipment	USI A-46	Fuel Cycle 12
12.9	Safety Parameter Display System (SPDS) Computer and Video Monitor	TMI I.D.2.1 TMI I.D.2.2 TMI I.D.2.3	Fuel Cycle 12
12.10	Single Failure Analysis of Safety Systems	SEP VI-7.C.2	Fuel Cycle 12
12.11	RG 1.97 (Post Accident Instrumentation)	Sup 1 to NUREG 0737	Fuel Cycle 12
12.12	Steam Generator Overfill (Control System Malfunction)	USI-A47 SEP XV-1, GL 89-19	Fuel Cycle 12
12.13	Safety Injection System/Recirc Upgrade	Safety Enhancement	Fuel Cycle 12
12.14	Control Room Design Review (CRDR)	TMI I.D.1	Fuel Cycle 12
12.15	Steel Plating Under the Turbine Deck (Heavy Load Drop Protection)	NUREG-0612	Fuel Cycle 12
12.16	Control Room Post Accident Habitability Evaluation	SEP II-1.C, TMI III.D.3.4.1, TMI III.D.3.4.2	Fuel Cycle 12
12.17	Synchrocheck Relay to Ensure Proper Loading of Emergency Diesel Generator	GSI-91, NUREG-1216	Fuel Cycle 12
12.18	Charging System Valves LCV 1100 B, C, D Single Failure Susceptibility	IE Bulletin 80-06	Fuel Cycle 11
12.19	Reactor Vessel Level Indication System (RVLIS/CET)	TMI II.F.2	Fuel Cycle 12
12.20	Waste Gas Decay Tank	Safety Enhancement	Complete

APPENDIX B

January 2, 1990 ORDER ITEMS
(Continued)

Item	Description	Source or Requirement	Completion
12.21	Modifications to Allow for Inservice Test of Equipment	10 CFR 50.55, GL 89-04	Fuel Cycle 12

APPENDIX C

NUCLEAR REGULATORY COMMISSION

COMPLETION OF SEISMIC MODIFICATIONS

LETTER OF JULY 11, 1986

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

July 11, 1986

RECEIVED
JUL 2 1 1986
NUCLEAR LICENSING

Docket No.: 50-206

Mr. Kenneth P. Baskin, Vice President
Nuclear Engineering
Safety and Licensing Department
Southern California Edison Company
2244 Walnut Grove Avenue
P.O. Box 800
Rosemead, California 91770

Dear Mr. Baskin:

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 1 - LONG-TERM SERVICE (LTS) SEISMIC REEVALUATION PROGRAM

On November 21, 1984, the NRC issued to Southern California Edison Company (SCE) a Contingent Rescission of Suspension that authorized resumption of power operation of San Onofre Unit 1. In accordance with its specific terms San Onofre Unit 1 was permitted to resume operation prior to full completion of the seismic reevaluation program provided that the remainder of the seismic reevaluation program and all resulting plant modifications were completed by the end of the next (November 1985) refueling outage. Operation of the facility had been suspended under the terms of "Order Confirming Licensee Commitments on Seismic Upgrading" issued on August 11, 1982.

By letter dated June 5, 1986, SCE provided a submittal that documents the final scope of the San Onofre 1 seismic reevaluation program. This document lists the structures, systems and components and the methods of qualification for each. In addition, plant modifications resulting from the LTS review are also shown. All of the modifications are now completed.

The enclosed safety evaluation report and attached Technical Evaluation Reports, prepared by staff consultants, present the results of the staff's review of the seismic reevaluation program for San Onofre Unit 1. Based on the staff's review of the licensee's long-term service seismic reevaluation plan, and the detailed audits of its implementation, the staff concludes that the LTS program has been properly implemented such that there is reasonable assurance that the plant can safely withstand an 0.67g modified-Housner response spectrum earthquake.

The scope of seismic reevaluation includes those structures and components previously evaluated in support of the return to service in November 1984 as well as those required for maintaining cold shutdown condition or for accident mitigation.

As discussed in our November 21, 1984 letter, operability, as defined in the unit technical specifications, of structures, systems and components that are within the seismic reevaluation program scope, should be determined on the basis of the 0.67g modified-Housner spectrum earthquake. Thus, if it is determined that such a structure, system or component no longer satisfies this basis, reports shall be submitted in accordance with 10 CFR 50.72(b)(ii) and 10 CFR 50.73(a)(2)(ii).

Based on this review, the staff concludes that SCE has complied with the terms of the Contingent Rescission of Suspension issued on November 21, 1984.

Thomas M. Novak, Acting Director
Division of PWR Licenisng-A
Office of Nuclear Reactor Regulation

Enclosures:
As Stated

cc's w/enclosures:
See Next Page

cc
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APPENDIX D

SONGS 1 SEP TOPICS WHICH REQUIRED RESOLUTION

APPENDIX D

SONGS 1 SEP TOPICS WHICH REQUIRED RESOLUTION

Topic Number	Description	Resolution
II-1.C	Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities	Open. The only area requiring resolution is mitigation of potential toxic gases. This issue will be resolved during the Fuel Cycle 12 refueling outage. (January 2, 1990 Order Line Number 12.16.)
II-3.B	Flooding Potential and Protection Requirements	Pending NRC approval. This topic will be resolved under Topic III-3.A. (January 2, 1990 Order Line Number 11.10.)
II-4.F	Settlement of Foundations and Buried Equipment	Closed. This topic was resolved under Topic III-6.
III-1	Classification of Structures, Components, and Systems	Pending NRC approval. Edison's May 31, 1989 submittal is currently under NRC review. No plant modification required. (January 2, 1990 Order Line Number 11.2.)
III-2	Wind and Tornado Loadings	Pending NRC approval. Document justifying no modifications required due to low risk of tornado at SONGS submitted on August 31, 1990, and currently under NRC review. (January 2, 1990 Order Line Number 12.2.)
III-3.A	Effects of High Water Level on Structures	Pending NRC approval. Edison's August 22, 1986 submittal is under NRC review. Modification to drainage of buildings was completed during Fuel Cycle 11. (January 2, 1990 Order Line Number 11.1 and 11.10.)
III-3.C	Inservice Inspection of Water Control Structures	Closed. Edison has committed to increased surveillance of the seawall per submittal dated October 25, 1985. The NRC accepted this, as documented in the December 1986 Integrated Plant Safety Assessment Report (IPSAR, page 4-8).

APPENDIX D

SONGS 1 SEP TOPICS WHICH REQUIRED RESOLUTION
(Continued)

Topic Number	Description	Resolution
III-4.A	Tornado Missiles	Pending NRC approval. Document justifying no modifications due to low risk of tornado at SONGS submitted on August 31, 1990 and is currently under NRC review. (January 2, 1990 Order Line Number 12.2. To be resolved with Topic III-2.)
III-5.A	Effects of Pipe Break on Structures, Systems, and Components Inside Containment	Open. This topic to be resolved through analysis to be submitted during Fuel Cycle 11. (January 2, 1990 Order Line Number 12.3.)
III-5.B	Effects of Pipe Break Outside Containment	Open. This topic to be resolved through analysis to be submitted during Fuel Cycle 11. (January 2, 1990 Order Line Number 12.3.)
III-6	Seismic Design Considerations	Closed. Completion of major plant modifications in 1980's resolved this topic. NRC acceptance documented in letter dated July 11, 1986.
III-7.B	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria	Pending NRC approval. Analysis submitted on March 30, 1984 and currently under NRC review. No plant modification required. (January 2, 1990 Order Line Number 11.4.)
III-7.D	Containment Structural Integrity Tests	Closed. Analysis and testing showing containment met all criteria was accepted by the NRC (IPSAR Page Number 4-13).
III-8.A	Loose-Parts Monitoring and Core Barrel Vibration Monitoring	Closed. Results of risk analysis indicating low risk for this topic at SONGS 1 was accepted by the NRC (IPSAR Page Number 4-14).

APPENDIX D

SONGS 1 SEP TOPICS WHICH REQUIRED RESOLUTION
(Continued)

Topic Number	Description	Resolution
III-10.A	Thermal Overload Protection for Motors of Motor Operated Valves	Closed. Results of risk analysis indicating low risk for this topic at SONGS 1 was accepted by the NRC (IPSAR Page Number 4-15).
III-10.B	Reactor Coolant Pump Flywheel Integrity	Closed. Inspection procedure reviewed by the NRC and found acceptable (IPSAR Page Number 4-16).
IV-2	Reactor Control System Including Functional Design and Protection Against Single Failures	Closed. Results of risk analysis indicating low risk for this topic at SONGS 1 was accepted by the NRC (IPSAR Page Number 4-16).
V-5	Reactor Coolant Pressure Boundary Leakage Detection	Closed. NRC review of leakage detection system design, test procedures and Technical Specification changes resolved this topic (IPSAR Page Number 4-20).
V-10.A	Residual Heat Removal System Heat Exchanger Tube Failures	Closed. NRC review of system design and test procedures resolved this topic (IPSAR Page Number 4-22).
V-11.A	Requirements for Isolation of High and Low Pressure Systems	Closed. NRC review of system design and operating and test procedures resolved this topic (IPSAR Page Numbers 4-23, 24).
V-11.B	Residual Heat Removal System Interlock Requirements (Overpressure protection)	Pending NRC approval. A change to the Technical Specifications will be submitted and will resolve this topic during the Fuel Cycle 11. (January 2, 1990 Order Line Number 11.5.)
VI-1	Organic Materials and Post-Accident Chemistry	Closed. Resolved by preparation and implementation of a procedure to inspect paint inside containment (IPSAR Page Number 4.26).

APPENDIX D

SONGS 1 SEP TOPICS WHICH REQUIRED RESOLUTION
(Continued)

Topic Number	Description	Resolution
VI-4	Containment Isolation System	Closed. NRC review of system design resolved this topic (IPSAR Page Numbers 4-26 to 34).
VI-7.B	Realignment of Emergency Core Cooling System After Initial Injection of Water	Closed. Modification to automatically stop feedwater pumps resolved this topic (IPSAR Page Number 4-36). Modification installed during the Fuel Cycle 10 refueling outage.
VI-7.C.2	Emergency Core Cooling System Failure Mode Analysis (Physical Separation)	Pending NRC approval. Edison's resolution of this topic was submitted in Fuel Cycle 11. NRC acceptance expected by Fuel Cycle 12 refueling. (January 2, 1990 Order Line Number 12.10.)
VI-10.A	Testing of Reactor Protection System	Pending NRC approval. NRC currently reviewing Edison's June 15, 1990 and May 22, 1991 proposed Technical Specification change. Resolution expected by end of Fuel Cycle 11. (January 2, 1990 Order Line Numbers 11.16 and 12.4.)
VII-1.A	Electrical Isolation of Reactor Protection System from Non-Safety Systems	Closed. NRC review of system design resolved this topic (IPSAR Page Number 4-42).
VII-3	Systems Required for Safe Shutdown	Open. Topic to be resolved with III-5A and III-5B. (January 2, 1990 Order Line Number 12.3.)
VIII-1.A	Potential Equipment Failures Associated with Low Offsite Power Voltage	Open. Modification to resolve this topic will be installed during Fuel Cycle 12 refueling. (January 2, 1990 Order Line Number 12.5b.)
VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation	Closed. NRC review of system design and Edison risk study resolved this topic (IPSAR Page Number 4-47).

APPENDIX D

SONGS 1 SEP TOPICS WHICH REQUIRED RESOLUTION
(Continued)

Topic Number	Description	Resolution
VIII-4	Electrical Penetrations of Reactor Containment	Closed. Results of risk study showing low risk for this topic at SONGS 1 was accepted by the NRC (IPSAR Page Number 4-47).
IX-3	Reactor Equipment Cooling Water Systems	Closed. NRC review of Edison reliability study resolved this topic (IPSAR Page Number 4-49, 50). Salt Water Cooling System Reliability Study submitted to the NRC.
IX-5	Ventilation Systems	Closed. Procedure changes, thermal analysis of system, and risk study resolved this topic (IPSAR Page Number 4-51 to 53).
IX-6	Fire Protection	Closed. Superseded by 10 CFR 50.48 Appendix R. Installation of dedicated system to shut down plant in event of postulated fires and detailed analysis of all potential fires resolved this topic (IPSAR Page Number 4-53).
XV-1	Changes in Feedwater and Steam Flow Rates (Steam Generator Overfill)	Open. This topic to be resolved through analysis or modification of feedwater system by the end of the Fuel Cycle 12 refueling outage (January 2, 1990 Order Line Number 12.12).
XV-2	Steam System Piping Failures Inside and Outside Containment	Closed. Results of risk analysis showing low risk for this topic at SONGS 1 accepted by NRC as resolution of this topic (IPSAR Page Number 4-54). Third train of auxiliary feedwater installed during the Fuel Cycle 10 refueling outage.

APPENDIX E

EDISON LETTER TO

NUCLEAR REGULATORY COMMISSION

DATED APRIL 18, 1989

TMI ISSUES

AD12
SO123
NRC

April 18, 1989

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Gentlemen:

Subject: Docket Nos. 50-206, 50-361 and 50-362
TMI Action Plan Status
San Onofre Nuclear Generating Station
Units 1, 2 and 3

By letter dated April 14, 1989, the NRC staff requested that Southern California Edison (SCE) provide the implementation status for TMI Action Plan Items at San Onofre Nuclear Generating Station (SONGS) Units 1, 2 and 3.

The list of TMI Action Plan Items has been reviewed and annotated in accordance with the above noted letter to indicate the implementation status at SONGS. The annotated lists for Unit 1 and Units 2 and 3 are enclosed.

Because of the limited time allowed for this response, this review represents our best efforts, and the status indicated for each item is based solely on a review of pertinent correspondence and the Safety Evaluation Reports. SCE believes that the information provided is correct to the best of our knowledge and accurately reflects the TMI Action Plan implementation status at SONGS.

If you have any questions or require additional information, please call me.

Very truly yours,

L. T. Papay
Senior Vice President

1458P
Enclosure

cc: D. E. Hickman, NRC Project Manager, San Onofre Units 2 and 3
F. R. Huey, NRC Senior Resident Inspector, San Onofre Units 1, 2, and 3

bcc: (See attached sheet)

SAN ONOFRE UNIT 1

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS
I.A.1.1.1		SHIFT TECHNICAL ADVISOR - ON DUTY	C
*I.A.1.1.2		SHIFT TECHNICAL ADVISOR - TECH SPECS	C
*I.A.1.1.3	F001	SHIFT TECHNICAL ADVISOR - TRAINED PER LL CAT B	C
*I.A.1.1.4		SHIFT TECHNICAL ADVISOR - DESCRIBE LONG TERM PROGRAM	C)
I.A.1.2		SHIFT SUPERVISOR RESPONSIBILITIES	C
I.A.1.3.1	F002	SHIFT MANNING - LIMIT OVERTIMES	C
I.A.1.3.2	F002	SHIFT MANNING - MIN SHIFT CREW	C
I.A.2.1.1		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - SRO EXPER	C
I.A.2.1.2		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - SRO'S BE RO'S 1YR	C
I.A.2.1.3		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - 3 MO. TRAINING	C
I.A.2.1.4	F003	IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - MODIFY TRAINING	C
I.A.2.1.5		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - FACILITY CERTIF	C
I.A.2.3		ADMINISTRATION OF TRAINING PROGRAMS	C
I.A.3.1.1		REVISE SCOPE & CRITERIA FOR LICENSING EXAMS - INCREASE SCOPE	C
I.A.3.1.2		REVISE SCOPE & CRITERIA FOR LICENSING EXAMS - INCREASE PASSING GRADE	NA
I.A.3.1.3.A		REVISE SCOPE & CRIT. FOR LIC. EXAMS - SIMULATOR PLANTS WITH SIMULATORS	C
I.A.3.1.3.B		REVISE SCOPE & CRIT. FOR LIC. EXAMS - SIMULATOR - OTHER PLANTS	NA
*I.B.1.2		EVALUATION OF ORGANIZATION & MANAGEMENT	C
I.C.1.1		SHORT-TERM ACCIDENT & PROCEDURES REVIEW - SB LOCA	Open - Unit 3 C
I.C.1.2.A	F004	SHORT-TERM ACCID. & PROCEDURES REV. - INADEQ. CORE COOL. REANAL. GUIDELINES	C
I.C.1.2.B	F004	SHORT-TERM ACCID. & PROCEDURES REV. - INADEQ. CORE COOL. REVISE PROCEDURES	Open - Unit 3
I.C.1.3.A	F005	SHORT-TERM ACCID. & PROCEDURES REV - TRANSIENTS & ACCDTS. REANAL GUIDELINES (PROC. GEN. PKG.)	C
I.C.1.3.B	F005	SHORT-TERM ACCID. & PROCEDURES REV. - TRANSIENTS & ACCDRS. REVISE PROCEDURES (UPGRADED EOP'S)	C
I.C.2		SHIFT & RELIEF TURNOVER PROCEDURES	C
I.C.3		SHIFT-SUPERVISOR RESPONSIBILITY	C
I.C.4		CONTROL-ROOM ACCESS	C
I.C.5	F006	FEEDBACK OF OPERATING EXPERIENCE	C
I.C.6	F007	VERIFY CORRECT PERFORMANCE OF OPERATING ACTIVITIES	NA
*I.C.7.1		NSSS VENDOR REV. OF PROC - LOW POWER TEST PROGRAM	NA
*I.C.7.2		NSSS VENDOR REV. OF PROC - POWER ASCENSION & EMER. PROCS	NA
*I.C.8		PILOT MON OF SELECTED EMERGENCY PROC FOR NTOLS	C
I.D.1	(See F008 & F071)	CONTROL-ROOM DESIGN REVIEWS (ENTER DATA FOR MPA F008 & MPA F-071)	
I.D.2.1	F009	PLANT-SAFETY PARAMETER DISPLAY CONSOLE - DESCRIPTION	open - Unit 1 options for SPDS under evaluation

Unit 1 submittal on implementation of NRC recommendations for PGP is scheduled 60 days following units return to service

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	Unit 1	LICENSEE IMPLEMENTATION STATUS
I.D.2.2	F009	PLANT-SAFETY PARAMETER DISPLAY CONSOLE - INSTALLED	open	FINAL SPDS TO BE SCHEDULED ON
I.D.2.3	F009	PLANT-SAFETY PARAMETER DISPLAY CONSOLE - FULLY IMPLEMENTED	open	ITS (IMPLEMENTATION AS EARLY AS 9/92)
*I.G.1.1		TRAINING DURING LOW-POWER TESTING - PROPOSE TESTS		N/A
*I.G.1.2		TRAINING DURING LOW-POWER TESTING - SUBMIT ANAL. & PROCS		N/A
*I.G.1.3		TRAINING DURING LOW-POWER TESTING - TRAINING & RESULTS		N/A
II.B.1.1		REACTOR-COOLANT SYSTEM VENTS - DESIGN VENTS		C
II.B.1.2	F010	REACTOR-COOLANT SYSTEM VENTS - INSTALL VENTS (LL CAT B)		C
II.B.1.3	F010	REACTOR-COOLANT SYSTEM VENTS - PROCEDURES		C
II.B.2.1		PLANT SHIELDING - REVIEW DESIGNS		C
*II.B.2.2		PLANT SHIELDING - CORRECTIVE ACTIONS TO ASSURE ACCESS		C
*II.B.2.3	F011	PLANT SHIELDING - PLANT MODIFICATIONS (LL CAT B)		C
*II.B.2.4		PLANT SHIELDING - EQUIPMENT QUALIFICATION- NOT TRACKED AS A TMI ACTION ITEM		
*II.B.3.1		POSTACCIDENT SAMPLING - INTERIM SYSTEM		C
*II.B.3.2		POSTACCIDENT SAMPLING - CORRECTIVE ACTIONS		C
*II.B.3.3		POSTACCIDENT SAMPLING - PROCEDURES		C
*II.B.3.4	F012	POSTACCIDENT SAMPLING - PLANT MODIFICATIONS (LL CAT B)		C
II.B.4.1	F013	TRAINING FOR MITIGATING CORE DAMAGE - DEVELOP TRAINING PROGRAM		C
*II.B.4.2.A	F013	TRAINING FOR MITIGATING CORE DAMAGE - INITIAL		C
*II.B.4.2.B	F013	TRAINING FOR MITIGATING CORE DAMAGE - COMPLETE		C
II.D.1.1		RELIEF & SAFETY VALVE TEST REQUIREMENTS - SUBMIT PROGRAM		C
*II.D.1.2.A		RELIEF & SAFETY VALVE TEST REQUIREMENTS - COMPLETE TESTING	Unit 1	C
*II.D.1.2.B	F014	RELIEF & SAFETY VALVE TEST REQUIREMENTS - PLANT SPECIFIC REPORT	open - AUDIT PENDING	12/90 Additional Info
II.D.1.3		RELIEF & SAFETY VAVLE TEST REQUIREMENTS - BLOCK-VALVE TESTING		C
*II.D.3.1		VALVE POSITION INDICATION - INSTALL DIRECT INDICATIONS OF VALVE POS		C
*II.D.3.2		VALVE POSTION INDICATION - TECH SPECS		C
*II.E.1.1.1 (SEE NOTE 1)	F015	AFS EVALUATION-ANALYSIS		C
*II.E.1.1.2 (SEE NOTE 2)	F015	AFS EVALUATION-SHORT TERM MODS		C
II.E.1.1.3 (SEE NOTE 3)	F015	AFS -LONG TERM MODS		C

NOTE 1 - THE ITEM LISTED IS FROM NUREG-0737, ENCLOSURE 2 AND IS APPLICABLE TO NTOLS'S ONLY
NOTE 2 - THE ITEM LISTED IS FOR ALL PLANTS (OPERATING REACTORS AND NTOL'S)
NOTE 3 - THE ITEM LISTED IS FOR ALL PLANTS (OPERATING REACTORS AND NTOL'S)

Additional information to be completed prior to return to service from the Cycle 11 refueling outage per NRC February 24, 1989 letter

E-3

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS
II.E.1.2.1.A		AFS INITIATION & FLOW-CONTROL GRADE	C
II.E.1.2.1.B	F016	AFS INITIATION & FLOW - SAFETY GRADE:	C
II.E.1.2.2.A		AFS INITIATION & FLOW - FLOW INDICATION CONTROL GRADE	C
*II.E.1.2.2.B		AFS INITIATION & FLOW - LL CAT A TECH SPECS	C
*II.E.1.2.2.C	F017	AFS INITIATION & FLOW - SAFETY GRADE	C
*II.E.3.1.1		EMERGENCY POWER FOR PRESSURIZER HEATERS - UPGRADE POWER SUPPLY	C
*II.E.3.1.2		EMERGENCY POWER FOR PRESSURIZER HEATERS - TECH SPECS	C
II.E.4.1.1		DEDICATED HYDROGEN PENETRATIONS - DESIGN	N/A
*II.E.4.1.2		DEDICATED HYDROGEN PENETRATIONS - REVIEW & REVISE H2 CONTROL PROC	N/A
*II.E.4.1.3	F018	DEDICATED HYDROGEN PENETRATION - INSTALL	N/A
II.E.4.2.1-4		CONTAINMENT ISOLATION DEPENDABILITY - IMP. DIVERSE ISOLATION	C
*II.E.4.2.5.A		CONTAINMENT ISOLAT. DEPENDABILITY - CNTMT PRESS. SETPT. SEECIFIY PRESS	C
*II.E.4.2.5.B		CONTAINMENT ISOLATION DEPENDABILITY - CNTMT PRESSURE SETPT. MODS	C
II.E.4.2.6	F019	CONTAINMENT ISOLATION DEPENDABILITY - CNTMT PURGE VALVES	C
II.E.4.2.7	F019	CONTAINMENT ISOLATION DEPENDABILITY - RADIATION SIGNAL ON PURGE VALVES	C
*II.E.4.2.8		CONTAINMENT ISOLATION DEPENDABLITY - TECH SPECS	C
*II.F.1.1	F020	ACCIDENT - MONITORING - PROCEDURES	C
*II.F.1.2.A	F020	ACCIDENT - MONITORING - NOBLE GAS MONITOR	C
*II.F.1.2.B	F021	ACCIDENT - MONITORING - IODINE/PARTICULATE SAMPLING	C
*II.F.1.2.C	F022	ACCIDENT - MONITORING - CONTAINMENT HIGH-RANGE MONITOR	C
*II.F.1.2.D	F023	ACCIDENT - MONITORING - CONTAINMENT PRESSURE	C
*II.F.1.2.E	F024	ACCIDENT - MONITORING - CONTAINMENT WATER LEVEL	C
*II.F.1.2.F	F025	ACCIDENT - MONITORING - CONTAINMENT HYDROGEN	C
*II.F.2.1		INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE COOLING - PROCEDURES	C
*II.F.2.2		INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE COOLING - SUBCOOL METER	open 12/92 HARDWARE
*II.F.2.3	F026	INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE COOLING - DESC. OTHER	open (CETs and RVLIS,
*II.F.2.4	F026	INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE CLING INSTLL ADD'L INSTRUMENTATION	
*II.G.1.1		POWER SUPP. FOR PRESSURIZER RELIEF, BLOCK VALVES & LEVEL IND. - UPGRADE	C
*II.G.1.2		POWER SUPP. FOR PRESSURIZER RELIEF, BLOCK VALVES & LEVEL IND. - TECH SP	C
II.K.1 (Oper. Reactors Only)		IE BULLETINS - 79-05, 79-06, 79-08	

(CETs scheduled to be upgraded during Cycle 12 refueling outage (~9/92). (IES 12/30/88)
NRC reviewing SCE's exception to install a RVLIS. (SCE letter 8/8/88)

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS
*II.K.1.5		*IE BULLETINS - REVIEW ESF VALVES	NA
*II.K.1.10		IE BULLETINS - OPERABILITY STATUS	NA
*II.K.1.20		IE BULLETINS - PROMPT MANUAL REACTOR TRIP	NA
*II.K.1.21		IE BULLETINS - AUTO SG ANTICIPATORY REACTOR TRIP	NA
*II.K.1.22		IE BULLETINS - AUX. HEAT REM SYSTEM, PROC.	NA
*II.K.1.23		IE BULLETINS - RV LEVEL, PROCEDURES	NA
*II.K.2.2		ORDERS ON B&W PLANTS - PROCEDURES TO CONTROL AFW IND OF ICS	NA
*II.K.2.8		ORDERS ON B&W PLANTS - UPGRADE AFW SYSTEM	NA
II.K.2.9	F027	ORDERS ON B&W PLANTS - FEMA ON ICS	NA
II.K.2.10	F028	ORDERS ON B&W PLANTS - SAFETY-GRADE TRIP	NA
*II.K.2.11	F029	ORDERS ON B&W PLANTS - OPERATOR TRAINING	NA
II.K.2.13	F030	ORDERS ON B&W PLANTS - THERMAL MECHANICAL REPORT (CE & W PLANTS ALSO)	C
II.K.2.14	F031	ORDERS ON B&W PLANTS - LIFT FREQUENCY OF PORV'S & SV's	NA
II.K.2.15		ORDERS ON B&W PLANTS - EFFECTS OF SLUG FLOW	NA
II.K.2.16	F032	ORDERS ON B&W PLANTS - RCP SEAL DAMAGE	NA
II.K.2.17	F033	ORDERS ON B&W PLANTS - VOIDING IN RCS (CE & W PLANTS ALSO)	C
II.K.2.19		BENCHMARK ANALYSIS OF SEQUENTIAL AFW FLOW TO ONCE THROUGH STM GENERATOR	NA
*II.K.2.20	F035	ORDERS ON B&W PLANTS - SYSTEM RESPONSE TO SB LOCA	NA
*II.K.3.1.A	F036	B&O TASK FORCE - AUTOMATIC PORV ISOLATION DESIGN	NC
*II.K.3.1.B		FINAL RECOMMENDATIONS, B&O TASK FORCE - AUTO PORV ISO TEST/INSTALL	NA
II.K.3.2	F037	B&O TASK FORCE - REPORT ON PORV FAILURES	C
II.K.3.3	F038	B&O TASK FORCE - REPORTING SV & RV FAILURES AND CHALLENGES	C
II.K.3.5.A	F039	B&O TASK FORCE - AUTO TRIP OF RCP'S PROPOSED MODIFICATIONS	C
II.K.3.5.B	F039	B&O TASK FORCE - AUTO TRIP OF RCP'S MODIFICATIONS	C
II.K.3.7		B&O TASK FORCE - EVALUATION OF PORV OPENING PROBABILITIES	NA
II.K.3.9	F040	B&O TASK FORCE - PID CONTROLLER MODIFICATION	C
II.K.3.10	F041	B&O TASK FORCE - PROPOSED ANTICIPATORY TRIP MODIFICATIONS	NA
II.K.3.11		B&O TASK FORCE - JUSTIFY USE OF CERTAIN PORV	C
II.K.3.12.A		B&O TASK FORCE - ANTICIPATORY TRIP ON TURBINE TRIP PROPOSED MODS	NC
II.K.3.12.B	F042	B&O TASK FORCE - ANTICIPATORY TRIP ON TURBINE TRIP INSTALL MODS	NC
II.K.3.13.A	F043	B&O TASK FORCE - HPCI & RCIC SYSTEM INITIATION LEVELS ANALYSIS	NA
II.K.3.13.B	F043	B&O TASK FORCE - HPCI & RCIC INITIATION LEVELS MODIFICATION	NA

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS
*II.K.3.14	F044	•B&O TASK FORCE - ISO CONDENSER ISOLATION ON HIGH RAD	NA
II.K.3.15	F045	B&O TASK FORCE - MODIFY HPCI & RCIC BRK DETECTION CIRCUITRY	NA
II.K.3.16A	F046	B&O TASK FORCE - CHALLENGE & FAILURE OF RELIEF VALVES STUDY	NA
II.K.3.16.B	F046	B&O TASK FORCE - CHALLENGE & FAILURE OF RELIEF VALVES MODIFICATIONS	NA
II.K.3.17	F047	B&O TASK FORCE - ECC SYSTEM OUTAGES	C
II.K.3.18.A	F048	B&O TASK FORCE - ADS ACTUATION STUDY	NA
II.K.3.18.B	F048	B&O TASK FORCE - ADS ACTUATION PROPOSED MODIFICATIONS	NA
II.K.3.18.C	F048	B&O TASK FORCE - ADS ACTUATION MODIFICATIONS	NA
*II.K.3.19	F049	B&O TASK FORCE - INTERLOCK RECIRCULATORY PUMP MODIFICATIONS	NA
*II.K.3.20		B&O TASK FORCE - LOSS OF SVC WATER AT BRP	NA
II.K.3.21.A	F050	B&O TASK FORCE - RESTART OF CSS & LPCI LOGIC DESIGN	NA
II.K.3.21.B	F050	B&O TASK FORCE - RESTART OF CSS & LPCI LOGIC DESIGN MODIFICATIONS	NA
II.K.3.22.A	F051	B&O TASK FORCE - RCIC SUCTION VERIFICATION PROCEDURES	NA
II.K.3.22.B	F051	B&O TASK FORCE - RCIC SUCTION MODIFICATION	NA
II.K.3.24	F052	B&O TASK FORCE - SPACE COOLING FOR HPCI/RCI LOSS OF AC POWER	NA
II.K.3.25.A		B&O TASK FORCE - POWER ON PUMP SEALS PROPOSED MODIFICATIONS	NC
II.K.3.25.B	F053	B&O TASK FORCE - POWER ON PUMP SEALS MODIFICATIONS	NC
II.K.3.27	F054	B&O TASK FORCE - COMMON REFERENCE LEVEL FOR BWRS	NA
II.K.3.28	F055	B&O TASK FORCE - QUALIFICATION OF ADS ACCUMULATORS	NA
*II.K.3.29	F056	B&O TASK FORCE - PERFORMANCE OF ISOLATION CONDENSERS	NA
II.K.3.30.A		B&O TASK FORCE - SCHEDULE FOR OUTLINE OF SB LOCA MODEL	C
II.K.3.30.B	F057	B&O TASK FORCE - SB LOCA MODEL, JUSTIFICATION	C
II.K.3.30.C		B&O TASK FORCE - SB LOCA METHODS NEW ANALYSES	C
II.K.3.31	F058	B&O TASK FORCE - COMPLIANCE WITH CFR 50.46	C
*II.K.3.40		B&O TASK FORCE - RCP SEAL DAMAGE - COVERED BY II.K.2.16 AND II.K.3.25	NC
*II.K.3.43		B&O TASK FORCE - EFFECTS OF SLUG FLOW - COVERED BY II.K.2.15	NA
II.K.3.44	F059	B&O TASK FORCE - EVALUATE TRANSIENT WITH SINGLE FAILURE	NA
II.K.3.45	F060	B&O TASK FORCE - ANALYSES TO SUPPORT	NA
II.K.3.46	F061	RESPONSE TO LIST OF CONCERNS FROM ACRS CONSULTANT	NA
*II.K.3.57	F062	IDENTIFY WATER SOURCES PRIOR TO MANUAL ACTIVATION OF ADS	NA
III.A.1.1		EMERGENCY PREPAREDNESS, SHORT TERM	C

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS
III.A.1.2.1		*UPGRADE EMERGENCY SUPPORT FACILITIES - INTERIM TSC OSC & EOF	C
III.A.1.2.2 (SEE F063, F064, F065)		UPGRADE EMERGENCY SUPPORT FACILITIES-DESIGN-INCORP. INTO F063/F064/F065	C
III.A.1.2.3 (SEE F063, F064, F065)		UPGRADE EMER SUPPORT FACILITIES - MODS INCORPOR. INTO F063, F064 & F065	C
III.A.2.1	F067	UPGRADE PREPAREDNESS - UPGRADE EMERGENCY PLANS TO APP. ~~E, 10 CFR~~ 50	C
III.A.2.2	F068	UPGRADE PREPAREDNESS - METEOROLOGICAL DATA	open - Unit 1 NRC Letter 12/30/86 C
*III.D.1.1.1		PRIMARY COOLANT OUTSIDE CONTAINMENT - LEAK REDUCTION	C
*III.D.1.1.2		PRIMARY COOLANT OUTSIDE CONTAINMENT - TECH SPECS	C
III.D.3.3.1		INPLANT RAD. MONIT. - PROVIDE MEANS TO DETER. PRESENCE OF RADIOIODINE	C
III.D.3.3.2	F069	INPLANT RADIATION MONIT. - MODIFICATIONS TO ACCURATELY MEAS. IODINE	C
III.D.3.4.1	F070	CONTROL ROOM HABITABILITY - REVIEW	open - Unit 1
*III.D.3.4.2	F070	CONTROL ROOM HABITABILITY - SCHEDULE MODIFICATIONS	open Included 12/30/88 IIS C
*III.D.3.4.3		CONTROL ROOM HABITABILITY - IMPLEMENT MODIFICATIONS	open Cycle 12 outage (~9/92)
MPA-F008	F008	I.D.1.1 DETAILED CONTROL ROOM DESIGN REVIEW PROGRAM PLAN	C
MPA-F063	F063	III.A.1.2 TECHNICAL SUPPORT CENTER	C
MPA-F064	F064	III.A.1.2 OPERATIONAL SUPPORT CENTER	C open - Unit 2 open - U
MPA-F065	F065	III.A.1.2 EMERGENCY OPERATIONS FACILITY	C
MPA-F071	F071	I.D.1.2 DETAILED CONTROL ROOM REVIEW (FOLLOWUP TO F-8)	open
MPA-B072	B072	NUREG-0737 TECH SPECS (GENERIC LETTERS 82-16 & 83-02)	C
MPA-B083	B083	TECH SPEC COVERED BY GENERIC LETTERS 83-26 & 83-37 FOR NUREG-0737	C
67.4.1	G001	REACTOR COOLANT PUMP TRIP (GENERIC LETTER 85-12)	open RCP Trip remove during Cycle 12 (~9/92) refueling outage per 12/30/88 IIS.

Unit 1

Additional information requested by NRC, submitted 4/17/89.

CRDR completed with 12/17/87 submittal. Modifications to be implemented in accordance with 12/30/88 IIS during Cycle 12 (~9/92) and Cycle 13 (~1994) refueling outages

UNITS 2/3

NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS U2	U3
I.A.1.1.1		SHIFT TECHNICAL ADVISOR - ON DUTY	C	C
*I.A.1.1.2		SHIFT TECHNICAL ADVISOR - TECH SPECS	C	C
*I.A.1.1.3	F001	SHIFT TECHNICAL ADVISOR - TRAINED PER LL CAT B	C	C
*I.A.1.1.4		SHIFT TECHNICAL ADVISOR - DESCRIBE LONG TERM PROGRAM	C	C
I.A.1.2		SHIFT SUPERVISOR RESPONSIBILITIES	C	C
I.A.1.3.1	F002	SHIFT MANNING - LIMIT OVERTIMES	C	C
I.A.1.3.2	F002	SHIFT MANNING - MIN SHIFT CREW	C	C
I.A.2.1.1		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - SRO EXPER	C	
I.A.2.1.2		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - SRO'S BE RO'S 1YR	C	
I.A.2.1.3		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - 3 MO. TRAINING	C	C
I.A.2.1.4	F003	IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - MODIFY TRAINING	C	C
I.A.2.1.5		IMMEDIATE UPGRADING OF RO & SRO TRAINING AND QUAL. - FACILITY CERTIF	C	C
I.A.2.3		ADMINISTRATION OF TRAINING PROGRAMS	C	C
I.A.3.1.1		REVISE SCOPE & CRITERIA FOR LICENSING EXAMS - INCREASE SCOPE	C	C
I.A.3.1.2		REVISE SCOPE & CRITERIA FOR LICENSING EXAMS - INCREASE PASSING GRADE	C	C
I.A.3.1.3.A		REVISE SCOPE & CRIT. FOR LIC. EXAMS - SIMULATOR PLANTS WITH SIMULATORS	N/A	N/A
I.A.3.1.3.B		REVISE SCOPE & CRIT. FOR LIC. EXAMS - SIMULATOR - OTHER PLANTS	C	C
*I.B.1.2		EVALUATION OF ORGANIZATION & MANAGEMENT	C	C
I.C.1.1		SHORT-TERM ACCIDENT & PROCEDURES REVIEW - SB LOCA	C	C
I.C.1.2.A	F004	SHORT-TERM ACCID. & PROCEDURES REV. - INADEQ. CORE COOL. REANAL. GUIDELINES Open-Unit 3	C	C
I.C.1.2.B	F004	SHORT-TERM ACCID. & PROCEDURES REV. - INADEQ. CORE COOL. REVISE PROCEDURES	C	C
I.C.1.3.A	F005	SHORT-TERM ACCID. & PROCEDURES REV - TRANSIENTS & ACCDTS. REANAL GUIDELINES (PROC. GEN. PKG.) Open-U	C	C
I.C.1.3.B	F005	SHORT-TERM ACCID. & PROCEDURES REV. - TRANSIENTS & ACCDRS. REVISE PROCEDURES (UPGRADED EOP'S)	C	C
I.C.2		SHIFT & RELIEF TURNOVER PROCEDURES	C	C
I.C.3		SHIFT-SUPERVISOR RESPONSIBILITY	C	C
I.C.4		CONTROL-ROOM ACCESS	C	C
I.C.5	F006	FEEDBACK OF OPERATING EXPERIENCE	C	
I.C.6	F007	VERIFY CORRECT PERFORMANCE OF OPERATING ACTIVITIES	C	
*I.C.7.1		NSSS VENDOR REV. OF PROC - LOW POWER TEST PROGRAM	C	C
*I.C.7.2		NSSS VENDOR REV. OF PROC - POWER ASCENSION & EMER. PROCS	C	C
*I.C.8		PILOT MON OF SELECTED EMERGENCY PROC FOR NTOLS	C	C
I.D.1	(See F008 & F071)	CONTROL-ROOM DESIGN REVIEWS (ENTER DATA FOR MPA F008 & MPA F-071)	C	C
I.D.2.1	F009	PLANT-SAFETY PARAMETER DISPLAY CONSOLE - DESCRIPTION Open-Unit 1		

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ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	Unit 1	LICENSEE IMPLEMENTATION STATUS U2	U3
I.D.2.2	F009	PLANT-SAFETY PARAMETER DISPLAY CONSOLE - INSTALLED.	open?	C	C
I.D.2.3	F009	PLANT-SAFETY PARAMETER DISPLAY CONSOLE - FULLY IMPLEMENTED.	open	C	C
*I.G.1.1		TRAINING DURING LOW-POWER TESTING - PROPOSE TESTS.		C	C
*I.G.1.2		TRAINING DURING LOW-POWER TESTING - SUBMIT ANAL. & PROCS.		C	C
*I.G.1.3		TRAINING DURING LOW-POWER TESTING - TRAINING & RESULTS.		C	C
II.B.1.1		REACTOR-COOLANT SYSTEM VENTS - DESIGN VENTS.		C	C
II.B.1.2	F010	REACTOR-COOLANT SYSTEM VENTS - INSTALL VENTS (LL CAT B).		C	C
II.B.1.3	F010	REACTOR-COOLANT SYSTEM VENTS - PROCEDURES.		C	C
II.B.2.1		PLANT SHIELDING - REVIEW DESIGNS.		C	C
*II.B.2.2		PLANT SHIELDING - CORRECTIVE ACTIONS TO ASSURE ACCESS.		C	C
*II.B.2.3	F011	PLANT SHIELDING - PLANT MODIFICATIONS (LL CAT B).		C	C
*II.B.2.4		PLANT SHIELDING - EQUIPMENT QUALIFICATION- NOT TRACKED AS A TMI ACTION ITEM.		C	C
*II.B.3.1		POSTACCIDENT SAMPLING - INTERIM SYSTEM.		C	C
*II.B.3.2		POSTACCIDENT SAMPLING - CORRECTIVE ACTIONS.		C	C
*II.B.3.3		POSTACCIDENT SAMPLING - PROCEDURES.		C	C
*II.B.3.4	F012	POSTACCIDENT SAMPLING - PLANT MODIFICATIONS (LL CAT B).		C	C
II.B.4.1	F013	TRAINING FOR MITIGATING CORE DAMAGE - DEVELOP TRAINING PROGRAM.		C	C
*II.B.4.2.A	F013	TRAINING FOR MITIGATING CORE DAMAGE - INITIAL.		C	C
*II.B.4.2.B	F013	TRAINING FOR MITIGATING CORE DAMAGE - COMPLETE.		C	C
II.D.1.1		RELIEF & SAFETY VALVE TEST REQUIREMENTS - SUBMIT PROGRAM.		C	C
*II.D.1.2.A		RELIEF & SAFETY VALVE TEST REQUIREMENTS - COMPLETE TESTING.		C	C
*II.D.1.2.B	F014	RELIEF & SAFETY VALVE TEST REQUIREMENTS - PLANT SPECIFIC REPORT.	Unit 1 open - audit pending	C	C
II.D.1.3		RELIEF & SAFETY VAVLE TEST REQUIREMENTS - BLOCK-VALVE TESTING.		C	C
*II.D.3.1		VALVE POSITION INDICATION - INSTALL DIRECT INDICATIONS OF VALVE POS.		C	C
*II.D.3.2		VALVE POSTION INDICATION - TECH SPECS.		C	C
*II.E.1.1.1 (SEE NOTE 1)	F015	AFS EVALUATION-ANALYSIS.			C
*II.E.1.1.2 (SEE NOTE 2)	F015	AFS EVALUATION-SHORT TERM MODS.		C	C
II.E.1.1.3 (SEE NOTE 3)	F015	AFS -LONG TERM MODS.			

NOTE 1 - THE ITEM LISTED IS FROM NUREG-0737, ENCLOSURE 2 AND IS APPLICABLE TO NTOLS'S ONLY
NOTE 2 - THE ITEM LISTED IS FOR ALL PLANTS (OPERATING REACTORS AND NTOL'S)
NOTE 3 - THE ITEM LISTED IS FOR ALL PLANTS (OPERATING REACTORS AND NTOL'S)

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS U2	U3
II.E.1.2.1.A		AFS INITIATION & FLOW-CONTROL GRADE	C	C
II.E.1.2.1.B	F016	AFS INITIATION & FLOW - SAFETY GRADE	C	C
II.E.1.2.2.A		AFS INITIATION & FLOW - FLOW INDICATION CONTROL GRADE	C	C
*II.E.1.2.2.B		AFS INITIATION & FLOW - LL CAT A TECH SPECS	C	C
*II.E.1.2.2.C	F017	AFS INITIATION & FLOW - SAFETY GRADE	C	C
*II.E.3.1.1		EMERGENCY POWER FOR PRESSURIZER HEATERS - UPGRADE POWER SUPPLY	C	C
*II.E.3.1.2		EMERGENCY POWER FOR PRESSURIZER HEATERS - TECH SPECS	C	C
II.E.4.1.1		DEDICATED HYDROGEN PENETRATIONS - DESIGN	N/A	N/A
*II.E.4.1.2		DEDICATED HYDROGEN PENETRATIONS - REVIEW & REVISE H2 CONTROL PROC	N/A	N/A
*II.E.4.1.3	F018	DEDICATED HYDROGEN PENETRATION - INSTALL	N/A	N/A
II.E.4.2.1-4		CONTAINMENT ISOLATION DEPENDABILITY - IMP. DIVERSE ISOLATION	C	
*II.E.4.2.5.A		CONTAINMENT ISOLAT. DEPENDABILITY - CNTMT PRESS. SETPT. SEECIFIY PRESS	C	
*II.E.4.2.5.B		CONTAINMENT ISOLATION DEPENDABILITY - CNTMT PRESSURE SETPT. MODS	C	C
II.E.4.2.6	F019	CONTAINMENT ISOLATION DEPENDABILITY - CNTMT PURGE VALVES	C	C
II.E.4.2.7	F019	CONTAINMENT ISOLATION DEPENDABILITY - RADIATION SIGNAL ON PURGE VALVES	C	C
*II.E.4.2.8		CONTAINMENT ISOLATION DEPENDABLITY - TECH SPECS	C	C
*II.F.1.1	F020	ACCIDENT - MONITORING - PROCEDURES	C	C
*II.F.1.2.A	F020	ACCIDENT - MONITORING - NOBLE GAS MONITOR	C	C
*II.F.1.2.B	F021	ACCIDENT - MONITORING - IODINE/PARTICULATE SAMPLING	C	C
*II.F.1.2.C	F022	ACCIDENT - MONITORING - CONTAINMENT HIGH-RANGE MONITOR	C	C
*II.F.1.2.D	F023	ACCIDENT - MONITORING - CONTAINMENT PRESSURE	C	C
*II.F.1.2.E	F024	ACCIDENT - MONITORING - CONTAINMENT WATER LEVEL	C	C
*II.F.1.2.F	F025	ACCIDENT - MONITORING - CONTAINMENT HYDROGEN	C	C
*II.F.2.1		INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE COOLING - PROCEDURES	C	C
*II.F.2.2		INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE COOLING - SUBCOOL METER	C	C
*II.F.2.3	F026	INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE COOLING - DESC. OTHER	C	C
*II.F.2.4	F026	INSTRUMENTATION FOR DETECT. OF INADEQUATE CORE CLING INSTLL ADD'L INSTRUMENTATION. open open (CCETS and	NC	N
*II.G.1.1		POWER SUPP. FOR PRESSURIZER RELIEF, BLOCK VALVES & LEVEL IND. - UPGRADE	C	C
*II.G.1.2		POWER SUPP. FOR PRESSURIZER RELIEF, BLOCK VALVES & LEVEL IND. - TECH SP	C	C
II.K.1 (Oper. Reactors Only)		IE BULLETINS - 79-05, 79-06, 79-08		

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ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS	
*II.K.1.5		*IE BULLETINS - REVIEW ESF VALVES	U2	U3
*II.K.1.10		IE BULLETINS - OPERABILITY STATUS	C	C
*II.K.1.20		IE BULLETINS - PROMPT MANUAL REACTOR TRIP	C	C
*II.K.1.21		IE BULLETINS - AUTO SG ANTICIPATORY REACTOR TRIP	N/A	N/A
*II.K.1.22		IE BULLETINS - AUX. HEAT REM SYSTEM, PROC	N/A	N/A
*II.K.1.23		IE BULLETINS - RV LEVEL, PROCEDURES	N/A	N/A
*II.K.2.2		ORDERS ON B&W PLANTS - PROCEDURES TO CONTROL AFW IND OF ICS	N/A	N/A
*II.K.2.8		ORDERS ON B&W PLANTS - UPGRADE AFW SYSTEM	N/A	N/A
II.K.2.9	F027	ORDERS ON B&W PLANTS - FEMA ON ICS	N/A	N/A
II.K.2.10	F028	ORDERS ON B&W PLANTS - SAFETY-GRADE TRIP	N/A	N/A
*II.K.2.11	F029	ORDERS ON B&W PLANTS - OPERATOR TRAINING	N/A	N/A
II.K.2.13	F030	ORDERS ON B&W PLANTS - THERMAL MECHANICAL REPORT (CE & W PLANTS ALSO)	C	[illegible]
II.K.2.14	F031	ORDERS ON B&W PLANTS - LIFT FREQUENCY OF PORV'S & SV's	N/A	N/A
II.K.2.15		ORDERS ON B&W PLANTS - EFFECTS OF SLUG FLOW	N/A	N/A
II.K.2.16	F032	ORDERS ON B&W PLANTS - RCP SEAL DAMAGE	N/A	N/A
II.K.2.17	F033	ORDERS ON B&W PLANTS - VOIDING IN RCS (CE & W PLANTS ALSO)	C	C
II.K.2.19		BENCHMARK ANALYSIS OF SEQUENTIAL AFW FLOW TO ONCE THROUGH STM GENERATOR	N/A	N/A
*II.K.2.20	F035	ORDERS ON B&W PLANTS - SYSTEM RESPONSE TO SB LOCA	N/A	N/A
*II.K.3.1.A	F036	B&O TASK FORCE - AUTOMATIC PORV ISOLATION DESIGN	N/A	N/A
*II.K.3.1.B		FINAL RECOMMENDATIONS, B&O TASK FORCE - AUTO PORV ISO TEST/INSTALL	N/A	N/A
II.K.3.2	F037	B&O TASK FORCE - REPORT ON PORV FAILURES	N/A	N/A
II.K.3.3	F038	B&O TASK FORCE - REPORTING SV & RV FAILURES AND CHALLENGES	C	C
II.K.3.5.A	F039	B&O TASK FORCE - AUTO TRIP OF RCP'S PROPOSED MODIFICATIONS	NC	NC
II.K.3.5.B	F039	B&O TASK FORCE - AUTO TRIP OF RCP'S MODIFICATIONS	NC	NC
II.K.3.7		B&O TASK FORCE - EVALUATION OF PORV OPENING PROBABILITIES	N/A	N/A
II.K.3.9	F040	B&O TASK FORCE - PID CONTROLLER MODIFICATION	N/A	N/A
II.K.3.10	F041	B&O TASK FORCE - PROPOSED ANTICIPATORY TRIP MODIFICATIONS	N/A	N/A
II.K.3.11		B&O TASK FORCE - JUSTIFY USE OF CERTAIN PORV	N/A	N/A
II.K.3.12.A		B&O TASK FORCE - ANTICIPATORY TRIP ON TURBINE TRIP PROPOSED MODS	N/A	N/A
II.K.3.12.B	F042	B&O TASK FORCE - ANTICIPATORY TRIP ON TURBINE TRIP INSTALL MODS	N/A	N/A
II.K.3.13.A	F043	B&O TASK FORCE - HPCI & RCIC SYSTEM INITIATION LEVELS ANALYSIS	N/A	N/A
II.K.3.13.B	F043	B&O TASK FORCE - HPCI & RCIC INITIATION LEVELS MODIFICATION	N/A	N/A

ISSUE NUMBER	MULTI-PLANT ACTION NO.	ISSUE TITLE	LICENSEE IMPLEMENTATION STATUS U2	U3
*II.K.3.14	F044	B&O TASK FORCE - ISO CONDENSER ISOLATION ON HIGH RAD.	N/A	N/A
II.K.3.15	F045	B&O TASK FORCE - MODIFY HPCI & RCIC BRK DETECTION CIRCUITRY.	N/A	N/A
II.K.3.16A	F046	B&O TASK FORCE - CHALLENGE & FAILURE OF RELIEF VALVES STUDY.	N/A	N/A
II.K.3.16.B	F046	B&O TASK FORCE - CHALLENGE & FAILURE OF RELIEF VALVES MODIFICATIONS.	N/A	N/A
II.K.3.17	F047	B&O TASK FORCE - ECC SYSTEM OUTAGES.	C	C
II.K.3.18.A	F048	B&O TASK FORCE - ADS ACTUATION STUDY.	N/A	N/A
II.K.3.18.B	F048	B&O TASK FORCE - ADS ACTUATION PROPOSED MODIFICATIONS.	N/A	N/A
II.K.3.18.C	F048	B&O TASK FORCE - ADS ACTUATION MODIFICATIONS.	N/A	N/A
*II.K.3.19	F049	B&O TASK FORCE - INTERLOCK RECIRCULATORY PUMP MODIFICATIONS.	N/A	N/A
*II.K.3.20		B&O TASK FORCE - LOSS OF SVC WATER AT BRP.	N/A	N/A
II.K.3.21.A	F050	B&O TASK FORCE - RESTART OF CSS & LPCI LOGIC DESIGN.	N/A	N/A
II.K.3.21.B	F050	B&O TASK FORCE - RESTART OF CSS & LPCI LOGIC DESIGN MODIFICATIONS.	N/A	N/A
II.K.3.22.A	F051	B&O TASK FORCE - RCIC SUCTION VERIFICATION PROCEDURES.	N/A	N/A
II.K.3.22.B	F051	B&O TASK FORCE - RCIC SUCTION MODIFICATION.	N/A	N/A
II.K.3.24	F052	B&O TASK FORCE - SPACE COOLING FOR HPCI/RCI LOSS OF AC POWER.	N/A	N/A
II.K.3.25.A		B&O TASK FORCE - POWER ON PUMP SEALS PROPOSED MODIFICATIONS.	NC	NC
II.K.3.25.B	F053	B&O TASK FORCE - POWER ON PUMP SEALS MODIFICATIONS.	NC	NC
II.K.3.27	F054	B&O TASK FORCE - COMMON REFERENCE LEVEL FOR BWRS.	N/A	N/A
II.K.3.28	F055	B&O TASK FORCE - QUALIFICATION OF ADS ACCUMULATORS.	N/A	N/A
*II.K.3.29	F056	B&O TASK FORCE - PERFORMANCE OF ISOLATION CONDENSERS.	N/A	N/A
II.K.3.30.A		B&O TASK FORCE - SCHEDULE FOR OUTLINE OF SB LOCA MODEL.	C	C
II.K.3.30.B	F057	B&O TASK FORCE - SB LOCA MODEL, JUSTIFICATION.	C	C
II.K.3.30.C		B&O TASK FORCE - SB LOCA METHODS NEW ANALYSES.	C	C
II.K.3.31	F058	B&O TASK FORCE - COMPLIANCE WITH CFR 50.46.	C	C
*II.K.3.40		B&O TASK FORCE - RCP SEAL DAMAGE - COVERED BY II.K.2.16 AND II.K.3.25.	N/A	N/A
*II.K.3.43		B&O TASK FORCE - EFFECTS OF SLUG FLOW - COVERED BY II.K.2.15.	N/A	N/A
II.K.3.44	F059	B&O TASK FORCE - EVALUATE TRANSIENT WITH SINGLE FAILURE.	N/A	N/A
II.K.3.45	F060	B&O TASK FORCE - ANALYSES TO SUPPORT.	N/A	N/A
II.K.3.46	F061	RESPONSE TO LIST OF CONCERNS FROM ACRS CONSULTANT.	N/A	N/A
*II.K.3.57	F062	IDENTIFY WATER SOURCES PRIOR TO MANUAL ACTIVATION OF ADS.	N/A	N/A
III.A.1.1		EMERGENCY PREPAREDNESS, SHORT TERM.	C	-

APPENDIX F

TMI ACTION ITEMS RESOLUTION

APPENDIX F

TMI ACTION ITEMS RESOLUTION

Issue	Description	Resolution
I.A.1.1.1 .2 .3 .4	Provide Shift Technical Advisor (STA) to aid Shift Supervisor. Establish training program for STA.	Closed. Requirements and training programs have been established as of January 1, 1980. NRC approval in letter dated November 15, 1982.
I.A.1.2	Revise, as necessary, the responsibilities of the Shift Supervisor (SS) to allow SS to manage operations important to safety.	Closed. Administrative procedures have been revised and subsequently approved by NRC, in letter dated May 2, 1980.
I.A.1.3.1 .2	Set operator overtime limits and minimum shift manning requirements.	Closed. Overtime policies were set in Edison May 1980 memo. Amendment 91 was made to Technical Specifications which included "minimum shift crew composition" NRC letter dated October 15, 1985.
I.A.2.1.1 .2 .3 .4 .5	Upgrade of reactor operator and senior reactor operator training and qualifications.	Closed. SONGS 1 operator training has been upgraded to applicable criteria. NRC approved in letter dated October 26, 1982
I.A.2.3	Operator training instructors who teach systems, integrated responses, transient, and simulator courses are to have senior reactor operator qualifications.	Closed. Instructors certified as Senior Reactor Operators as of August 1, 1980.
I.A.3.1.1 .2 .3	Increase scope of training and increase passing grade. Simulator exams to be included as part of licensing examinations.	Closed. Training scope and passing grades increased; exams conducted on simulator.
I.C.1.1 .2a .2b .3a .3b	Guidance for the evaluation and development of procedures for transients and accidents.	Closed. NRC letter dated December 4, 1990 with NRC Inspection Report. Resolution of findings constitutes approval.

APPENDIX F

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
I.C.2	Ensure a complete and systematic turnover of operators between off-going and on-coming shifts.	Closed. Shift turnover checklist has been implemented and approved in NRC's May 2, 1980 letter.
I.C.3	Revise, as necessary, the responsibilities of the shift supervisor to permit oversight of operations which are important to safety.	Closed. Administrative procedures have been revised and approved in NRC's March 10, 1980 letter.
I.C.4	Develop procedures that establish the authority of senior control room operator to limit control room access.	Closed. Procedure implemented to establish the Shift Supervisor or designee as the person in charge during accident conditions. Approved in NRC's May 2, 1980 letter.
I.C.5	Establish procedures to ensure that operator experience pertinent to safety be supplied to operating personnel.	Closed. Procedures for feedback of operator experience have been established and approved in NRC's January 27, 1982 letter.
I.C.6	Review procedures and revise as necessary to ensure correct performance of operating activities.	Closed. Procedures have been reviewed and revised and approved in NRC's February 4, 1982 letter.
I.D.1	Review of control room design.	Open. Item is to be completed during the Fuel Cycle 12 refueling outage (January 2, 1990 Order Line Number 12.14).
I.D.2.1 .2 .3	Computer and display which will define the safety status of the plant.	Open. This console will be installed during the Fuel Cycle 12 refueling outage (January 2, 1990 Order Line Number 12.9).
II.B.1.1 .2 .3	Install remotely operated vents in reactor coolant system.	Closed. RCS and reactor vessel high points contain remotely operated vents. NRC approved in August 29, 1983 letter.

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
II.B.2.1 .2 .3	Radiation and shielding review for post-accident radiation levels in vital control centers.	Closed. Shielding was reviewed and upgraded as necessary and NRC approved in April 18, 1983 letter.
II.B.3.1 .2	Review of RCS and containment atmosphere sampling system and procedures to ensure ability to obtain samples under accident conditions.	Closed. Sampling system and procedures have been upgraded and NRC approved in November 7, 1985 letter.
II.B.4.1 .2a .2b	Develop and implement training program to improve operator's control or mitigation of accidents which may cause core damage.	Closed. Training program has been implemented to address postulated core damage accidents. NRC approved in letter dated October 26, 1982.
II.D.1.1 .2a .2b .3	Conduct testing program on RCS relief valves and safety valves.	Closed. Edison has completed open items and responses are available on-site for future audit. NRC notified by letter dated February 8, 1991.
II.D.3.1 .2	Provide positive indication in the control room of RCS relief valve position.	Closed. Indicators have been installed and NRC approved in letter dated May 2, 1980.
II.E.1.1.1 .2	Evaluate auxiliary feedwater (AFW) system reliability.	Closed. Performed AFW evaluation and reported results to NRC. Approval in NRC letter dated October 22, 1982.
II.E.1.2.1a .1b .2a .2b .2c	Ensure automatic initiation of auxiliary feedwater system and proper flow indication.	Closed. Auxiliary feedwater system and associated technical specifications have been modified and NRC approved in letters dated November 18, 1982 and April 29, 1989.
II.E.3.1.1 .2	Ensure emergency power for pressurized heaters during accident conditions.	Closed. Pressurizer heaters and controls can be supplied from off-site power or emergency power. NRC approval in letter dated May 2, 1980.
II.E.4.1.1	Dedication of connecting	Closed. Edison has installed

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
.2	lines for combustible gas recombiners located outside the containment.	redundant safety grade recombiners inside the containment in response to NUREG-0578. NRC approval in letter dated November 2, 1982.
II.E.4.2.1 .2 .3 .4	Containment isolation system to ensure that all nonessential systems can be automatically isolated by a containment isolation signal. Signal to come from diverse parameters.	Closed. NUREG-0737 documented this item as completed for all plants as of October 31, 1980. NRC Safety Evaluation dated November 6, 1981.
II.E.4.2.5.a .b	Reduce containment isolation initiation setpoint.	Closed. Containment isolation setpoint is set at 1.4 psig. NRC approved this in letter dated January 11, 1982.
II.E.4.2.6	Containment purge valves not conforming to Branch Technical Position CSB 604 or staff Interim Position of October 1979 must be sealed closed.	Closed. One purge valve on each line is closed and locked. Surveillance procedures were modified to verify lock every 31 days. Approved in NRC letter December 30, 1982.
II.E.4.2.7	Purge and vent valves must close on high radiation signal.	Closed. The containment purge and vent valves close on high radiation signal. Approved in NRC letter dated December 30, 1982.
II.E.4.2.8	Containment Isolation Technical Specifications	Closed. New containment technical specifications were approved by NRC in letter dated November 6, 1981.
II.F.1.1	Provide wide range noble gas effluent monitors.	Closed. Monitors were operational by December 24, 1981. Technical specifications approved by NRC November 2, 1984.
II.F.1.2	Effluent monitoring for radioiodines.	Closed. Iodine sampling systems improved and operable on December 24, 1981, NRC approval in letter dated March 14, 1983.

APPENDIX F

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
II.F.1.3	Containment high-range radiation monitors.	Closed. Two high-range radiation monitors have been installed inside the containment. Approval in NRC Safety Evaluation dated November 2, 1984.
II.F.1.4	Monitors for containment pressure.	Closed. Containment pressure monitor approved by NRC in letter dated August 3, 1984.
II.F.1.5	Provide continuous indication of containment water level.	Closed. Containment water level monitor approved by NRC in letter dated April 16, 1984.
II.F.1.6	Provide continuous indication of hydrogen concentration inside containment.	Closed. Containment hydrogen monitor approved by NRC in letter dated April 16, 1984.
II.F.2.1 .2 .3	Instrumentation for detection of inadequate core cooling.	Open. (Item 3 only) A subcooling meter has been installed. A Reactor Vessel Level Indicating System and upgraded core exit thermocouples are scheduled to be installed during the Fuel Cycle 12 refueling outage (January 2, 1990 Order Line Number 12.19).
II.G.1.1 .2	Pressurizer relief valves and level indicators must have adequate emergency power supplies.	Closed. Pressurizer relief valves and level indicators can be supplied from off-site power or emergency power. Approved in NRC letter dated May 2, 1980.
II.K.1	IE Bulletin 79-05 and 79-06.	Closed. Edison has taken action to comply with bulletins and sent response to NRC.
II.K.2.13	Perform analysis of thermal-mechanical conditions on reactor vessel during small break LOCA.	Closed. Analysis shows reasonable assurance that reactor vessel integrity will be maintained. Approval in NRC letter dated June 13, 1984.

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
II.K.2.17	Analysis potential for formation of voids in RCS during anticipated transients.	Closed. Voids generated in SONGS 1 during anticipated transients are accounted for in present analysis methods and predicted voids will not result in unacceptable consequences. Approval in NRC letter dated December 19, 1983.
II.K.2.19	Provide analysis of auxiliary feedwater flow after loss of main feedwater.	Closed. NRC concluded in letter dated June 29, 1981 that TMI Item II.K.2.19 did not apply to SONGS 1.
II.K.3.1.a .b	Provide a system that uses a PORV block valve to prevent small break LOCA.	Closed. See II.K.3.2.
II.K.3.2	Install and test an automatic PORV block valve system.	Closed. Based on a Westinghouse Owners Group generic report, it was found not necessary to make this modification. NRC approval in letter dated September 13, 1983.
II.K.3.3	Report safety valve and relief valve failures and challenges.	Closed. Have committed to reporting on SV and RV failures and challenges. NRC approval in letter dated March 15, 1982.
II.K.3.5.a .b	RCPs to trip automatically in the event of a Small Break LOCA.	Closed. RCPs trip automatically on a SBLOCA. Order to remove RCP trip (January 2, 1990 Order Line Number 11.3) has been superseded by NRC letter dated October 16, 1990.
II.K.3.9	Modify Proportional Integral Derivative (PID) controller for PORVs.	Closed. SONGS 1 is not using PID controllers. NRC approved in letter dated January 4, 1982.
II.K.3.10	Anticipatory trip modification should be made on a plant-by-plant basis only.	Closed. Edison has not proposed a modification. Approved by NRC in letter dated January 4, 1982.

APPENDIX F

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
II.K.3.12.a .b	Confirm existence of Anticipatory Reactor Trip upon Turbine Trip.	Closed. Confirmed and reported to NRC. NRC acknowledged by letter dated January 4, 1982.
II.K.3.17	Report to NRC all outages of ECC system for past five years.	Closed. Report was sent to NRC, approved by NRC in letter dated August 8, 1983.
II.K.3.25.a .b	Ensure the integrity of the RCP seals during loss of AC power.	Closed. The RCP seals will be supplied by a DC pump in the event of complete loss of AC power. Approved in NRC letter dated July 7, 1982.
II.K.3.30.a .b .c	Revise small-break LOCA analysis methods.	Closed. The small break LOCA model "NOTRUMP" was submitted by Westinghouse and approved by the NRC in letter dated May 21, 1985.
II.K.3.31	Submit to NRC a plant specific analysis for SBLOCA.	Closed. Edison was using the Westinghouse Code WFLASH as a model for small break LOCA at SONGS 1. In Generic Letter 83-35, the NRC permits the use of older LOCA models if it is shown to be conservative when compared to the newer NRC-approved models. It was shown that WFLASH analysis for SONGS 1 was more conservative than the NRC-approved model NOTRUMP, so the NRC approved the use of WFLASH at SONGS 1 in letter dated April 5, 1987.
III.A.I.1	Short-term emergency preparedness.	Closed. NUREG-0737 documents this item as complete for all plants.
III.A.1.2.1 .2 .3	Provide an Operations Support Center (OSC) where emergency operations support personnel will assemble.	Closed. An OSC has been provided and NRC approved in letter dated December 30, 1986.

TMI ACTION ITEMS RESOLUTION
(Continued)

Issue	Description	Resolution
III.A.2.1 .2	Update emergency plans to provide reasonable assurance that adequate measures are taken in the event of a radiological emergency.	Closed. The emergency plans have been updated and NRC approved in letter dated May 9, 1983.
III.D.1.1.1 .2	Implement program to reduce the leak-rate in systems outside the containment that may contain radioactive materials.	Closed. Implemented program in 1979 and approved by the NRC in letter dated May 2, 1979.
III.D.3.3.1 .2	Provide system and training to detect airborne iodine in areas where personnel will be located during an accident.	Closed. NRC acknowledged no technical deviations from their stated position in letter dated February 22, 1982.
III.D.3.4.1 .2	Assure that control room operators are protected from release of toxic and radioactive gases during an accident.	Open. To be completed during Fuel Cycle 12 refueling outage (January 2, 1990 Order Line Number 12.16).

APPENDIX G

OPEN GENERIC SAFETY ISSUES

APPENDIX G
OPEN GENERIC SAFETY ISSUES

Issue Number	Description	Potential Impact
15	Radiation Effects on Reactor Vessel Supports	Probability of modification very low based on SONGS 1 reactor design. Most likely outcome expected to be lifetime limit on vessel which should have no impact on SONGS 1 operation.
23	Reactor Coolant Pump Seal Failures	Potential moderate modification to pump seal cooling system if results indicate SONGS 1-type pump seals are susceptible to failure which lead to increased risk.
29	Bolting Degradation or Failure in Nuclear Power Plants	No major modification required. Most likely impact to be issuance of an Information Notice to monitor performance of bolts in certain safety systems.
57	Effects of Fire Protection System Actuation on Safety Related Equipment	Potential moderate modification of fire protection system to ensure actuation only affects equipment actually on fire and not other safety related equipment.
70	Pressurizer Relief Valve Reliability	No major modification required. Most likely impact to be change in valve maintenance procedure and/or periodic testing procedure.
75	Quality Assurance Aspects of Failure of Automatic Reactor Trip System	No major modification required. Current NRC staff position is that this issue should be closed out with no further action required because other current regulations adequately address this issue.

APPENDIX G
OPEN GENERIC SAFETY ISSUES
(Continued)

Issue Number	Description	Potential Impact
79	Reactor Vessel Thermal Stress During Periods of No Forced Cooling (Reactor Coolant Pumps Turned Off)	No major modification required. Current status indicates NRC will issue an "information only" Generic Letter that will not require action by Edison.
83	Control Room Habitability	Moderate plant modifications to SONGS 1 to mitigate effect of radioactive and toxic gases entering the control room following postulated accidents.
84	CE Plant Pressurizer Relief Valves	Not applicable to SONGS 1.
87	Failure of BWR Safety Injection System	Not applicable to SONGS 1.
94	Low Temperature Overpressure Protection	No major modification required. Most likely impact is change to setpoint of existing overpressure protection equipment and changes to Technical Specifications.
105	Failures at Interface Between High and Low Pressure Systems Resulting in Loss of Coolant from the Reactor Coolant System	No major modification required. Most likely impact is change to test frequency of certain pressure isolation valves to ensure leak tightness.
106	Use of Highly Combustible Gases in Vital Areas	No major modification required. Potential minor modification to hydrogen systems in vital areas to ensure no excessive buildup of hydrogen would occur if pipes transporting hydrogen were to fail.
113	Dynamic Testing of Large Pipe Seismic Restraints	Potential moderate modification required. Most likely impact is change to seismic restraint equipment testing procedures.

APPENDIX G
OPEN GENERIC SAFETY ISSUES
(Continued)

Issue Number	Description	Potential Impact
121	Post Accident Control of Hydrogen Inside Containment	No major modification required. SONGS 1 already contains a hydrogen control system.
128	Electrical Power Reliability	No major modification required. Likely to impact surveillance testing procedures and Technical Specifications. Plant modifications are indeterminant.
130	Essential Service Water System Failures at Multiplant Sites	Potential moderate modification to add new pump. Most likely impact is change to Technical Specifications or testing procedures.
135	Overfill of Steam Generator (Tube Rupture)	Potential moderate modification to mitigate tube rupture or other events.
142	Leakage Through Electrical Isolators	No major modification required. No work being done by NRC on this issue currently. At most a minor modification to electrical isolators may be required.
B-17	Criteria for Safety Related Operator Actions	Most likely impact is change to operating procedures or operator training. May require moderate modifications to automate actions currently completed manually.
B-55	Improve Reliability of Target Rock Reactor Coolant System Safety Relief Valves	Not applicable to SONGS 1.
B-56	Diesel Generator Reliability	No major modification required. Most likely impact is change in requirements for documenting diesel generator performance.
B-61	Allowable Downtime for Safety Related Equipment	No major modification required. Most likely impact is a new procedural requirement to minimize the number and type of safety equipment that can be inoperable at one time.

Issue Number	Description	Potential Impact
B-64	Decommissioning of Nuclear Reactors	No major modifications required. Most likely impact to be changes to procedures and format of plans for decommissioning.
HF 4.4	Guidelines for Upgrading Other Procedures	No major modifications required. Impact on procedures only.
HF 5.1	Operator Actions at Local Control Stations (Outside the Control Room)	No major modifications required. Most likely impact will be on procedures and operator training.
HF 5.2	Risk of Operator Error Due to Inadequate Control Room Instrumentation Annunciators	No major modifications required. Most likely impact to be minor modification of annunciators to better alert operators to real or potential safety concerns.
I.D.3	Safety System Status Monitoring	No modifications required. Current NRC position is to apply this to new plants only. Operating plants can voluntarily comply.
I.D.5(3)	Analysis of Noise Generated in Reactor Core During Operation to Determine Potential Anomalies	No major modifications required. May result in minor modification to improve reactor noise monitoring system.
II.H.2	Obtain Data on Conditions Inside the TMI-2 Containment	No modifications required. This is an NRC research effort to determine potential amount of radioactivity released during an accident. May impact future risk study estimates.
II.J.4.1	Revise Reporting Requirements for Potential Safety Concerns	No modifications required. Change in reporting requirements to eliminate redundant safety evaluations and establish consistent safety concerns reporting requirements.

APPENDIX H

NRC MEMORANDUM FOR ISSUANCE OF OPERATING LICENSES WITH A 40-YEAR DURATION (OPERATING LICENSE RECAPTURE OF CONSTRUCTION PERIOD)