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March 19, 1981

Director, Office of Nuclear Reactor Regulation
Attention: D. M. Crutchfield, Chief
Operating Reactors Branch No. 5
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

Subject: Docket No. 50-206
Fire Protection Program Review
San Onofre Nuclear Generating Station
Unit 1

The new Fire Protection regulations, 10 CFR 50.48, which became effective on February 17, 1981, require that information regarding our plans and schedules for complying with these regulations be submitted by March 19, 1981. The purpose of this letter is to provide the required information.

Paragraph (c)(5) of 10 CFR 50.48 requires Licensees to "submit plans and schedules for meeting the provisions of paragraphs (c)(2), (c)(3), and (c)(4) within 30 days after the effective date of this section and Appendix R to this part." In accordance with Supplement No. 1 to the Fire Protection Safety Evaluation Report (FPSER) for San Onofre Unit 1 which was received by NRC letter dated February 4, 1981, the following items are to be implemented as indicated in paragraphs (c)(2), (c)(3), and (c)(4) of 10 CFR 50.48:

1. Install Smoke Detectors in various locations per Section III.F of Appendix R to 10 CFR 50. This includes items 3.1.1(2), (3), (4), (6), (9), (10) and (11) of Table 3.1 of the FPSER. The completion date for installation as specified in 10 CFR 50.48(c), is November 17, 1981 for modifications not requiring a plant outage and for modifications requiring plant outage, the installation is required to be completed on the following schedule commencing after August 16, 1981; a 60 day planned outage, a 120 day unplanned outage, or the next refueling outage.

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2. Install Emergency Lighting in various locations per Section III.J of Appendix R to 10 CFR 50. This includes item 3.1.17 of Table 3.1 of the FPSER. The completion date for installation, as specified in 10 CFR 50.48(c), is November 17, 1981 for modifications not requiring a plant outage. For modifications requiring a plant outage, the installation is required to be completed on the following schedule commencing after August 16, 1981; a 60 day planned outage, a 120 day unplanned outage, or the next refueling outage.

3. Install a Reactor Coolant Pump Lube Oil Collection System per Section III.O of Appendix R to 10 CFR 50. This includes item 3.1.15(5) of Table 3.1 of the FPSER. The completion date for installation, as specified in 10 CFR 50.48(c), is on the following schedule commencing after August 16, 1981; a 60 day planned outage, a 120 day unplanned outage, or the next refueling outage.

4. Provide a Safe Shutdown capability per Section III.G of Appendix R to 10 CFR 50. This includes item 3.1.11(e) of Table 3.1, and items 1, 4, and 5 of Table 3.2 of the FPSER. The completion date for installation, as specified in 10 CFR 50.48(c), is 30 months after NRC approval for Dedicated Shutdown modifications, 6 months after NRC approval for Alternate Shutdown modifications not requiring a plant outage. For Alternate Shutdown modifications requiring a plant outage, the instalation is required to be completed on the following schedule commencing 6 months after NRC approval; a 60 day planned outage, a 120 day unplanned outage, or the next refueling outage.

Items 1, 2, and 3 above have been reviewed, and based on conceptual engineering performed to date, it appears probable that each of the items can be completed on the required schedules. Accordingly, design and engineering activities associated with these items have been initiated. As these activities progress, we will be in a better position to assess our ability to complete the items as required based on detailed quantities, procurement lead times and construction unit rates. In addition, unforeseen schedular problems such as the need to reallocate resources (i.e., manpower), strikes, accessibility constraints, etc., may also impact our ability to complete these items as required. If we determine that items 1, 2 and 3 above cannot be completed as required, we will request an exemption from the schedular requirements for these items at that time.

Item 4 above has also been reviewed. An extensive effort has been completed to determine the impact of the requirements in this area. Based on conceptual engineering, we have determined that extensive modifications are necessary to comply with the requirements of Sections III.G of Appendix R. In addition, revised operating procedures will be required to address the use of redundant equipment to achieve safe shutdown following a fire in a specified area.

The modifications required include the addition of a new building to house new equipment, redundant 4 kV switchgear, a 480V/208V-120V transformer, a charging pump, an auxiliary feedwater train, approximately 12 motor operated valves and an instrument air compressor and receiver. In addition, approximately 10 motor operated valves and five instruments will need to be relocated. There will be approximately 580 circuits which will require relocation and approximately 300 circuits/raceways to be added to supply the redundant equipment described above. Numerous isolation devices will be required for associated circuits not yet identified.

In addition, fire barriers will be required between some redundant equipment. The remote shutdown panel will need to be modified to add hot shutdown equipment and the required cold shutdown equipment controls and instrumentation. In order to meet the requirement to assume loss of offsite power, a tie-in to one of the existing emergency diesel generators will be necessary to provide an onsite power source to the new switchgear described above.

Although many of the modifications identified above are associated with alternate shutdown capability (existing equipment), such as the great number of circuit reroutings which would be required, the safe shutdown capability as defined in Appendix R would not be available until the dedicated shutdown capability (new equipment) has been installed. This means that the safe shutdown capability is not required to be in place until 30 months after NRC approval of the proposed modifications.

A schedule based on 30 months for implementation of the safe shutdown capability (following NRC approval) is not incompatible with a schedule which would result from the implementation of similar modifications upon completion of the Systematic Evaluation Program (SEP) Integrated Assessment. Based upon existing NRC schedules, it is estimated that the SEP review will be complete and a Safety Evaluation Report issued in April, 1982. If the requirements of Appendix R were applied to the plant configuration resulting from potential modifications identified in the SEP review, we have determined that the extensive nature of the Fire Protection modifications described above could be reduced or integrated into potential modifications which result from the SEP Integrated Assessment. This determination is based on the fact that review topics included as part of SEP involve electrical and physical separation of safe shutdown components, electrical and physical separation of power sources required to operate safe shutdown equipment, and seismic qualification of structures and components required for safe shutdown.

Based on a value-impact assessment, the commitment to proceed with the extensive modifications to comply with the safe shutdown capability of Appendix R on the schedule required by 10 CFR 50.48(c) cannot be justified for San Onofre Unit 1. It has been estimated that the cost of implementing these modifications is approximately $40,000,000 without including differential fuel costs associated with replacement power during outage times. In addition, the schedule for completion of the SEP Integrated Assessment and that specified in 10 CFR 50.48(c) for safe shutdown capability, will coincide in approximately one year. The expenditure of the significant resources associated with

complying with the safe shutdown capability of Appendix R at the present time is justified only if compliance significantly improves the protection of the health and safety of the public. The increase in the protection of the health and safety of the public provided by the safe shutdown modifications described above is not commensurate with the expenditure of resources required for implementation of these modifications. Adequate protection, in the interim (approximately one year), is provided as discussed below.

As indicated in Table 3.1 of the FPSER Supplement No. 1, a large number of fire protection modifications have already been implemented. In accordance with NRC guidance and previously approved schedules, we are proceeding with additional Fire Protection modifications. In addition, as indicated in the original FPSER dated July 19, 1979, several measures have already been taken to provide alternate shutdown capability in the interim by the installation of an additional source of offsite power, modifications to the station air system, provisions for isolation capability of affected control systems, and development of station procedures.

Based on the information presented above, Southern California Edison Company, in the near future, will be formally requesting an exemption under 10 CFR 50.12(a) from the schedular requirements of 10 CFR 50.48(c) for the modifications required by Section III.G of Appendix R to 10 CFR 50. Pending resolution of this exemption application, compliance with Section III.G of Appendix R to 10 CFR 50 will be evaluated as part of the fire protection of the safe shutdown capability resulting from modifications associated with SEP.

If you have any questions or desire additional information, please contact me.

Very truly yours,

K P Baskin

Enclosure