NUREG-0781
Supplement No. 5

Safety Evaluation Report
related to the operation of South Texas Project, Units 1 and 2

Docket Nos. 50-498 and 50-499

Houston Lighting and Power Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

March 1988

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ABSTRACT

In April 1986 the staff of the U.S. Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0781) regarding the application of Houston Lighting and Power Company (applicant and agent for the owners) for a license to operate South Texas Project, Units 1 and 2 (Docket Nos. 50-498 and 50-499). The facility is located in Matagorda County, Texas, west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. The first supplement to NUREG-0781 was issued in September 1986, the second supplement in January 1987, the third supplement in May 1987, and the fourth supplement in July 1987. This fifth supplement provides updated information on the issues that had been considered previously as well as the evaluation of issues that have arisen since the fourth supplement was issued. The evaluation resolves all the issues necessary to support the issuance of a full-power license for Unit 1.

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1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

In April 1986 the U.S. Nuclear Regulatory Commission (NRC) staff issued its Safety Evaluation Report (SER) (NUREG-0781) on the application filed by Houston Lighting and Power Company (HL&P) (the licensee) acting on behalf of itself and the other owners [City Public Service Board of San Antonio (CPS), Central Power and Light Company (CPL), and City of Austin (COA)] for a license to operate South Texas Project, Units 1 and 2, Docket Nos. 50-498 and 50-499. At that time the staff identified items that had not been resolved with the licensee. In the first supplement to the SER (SSER 1) published in September 1986, the status of unresolved items and the comments made by the Advisory Committee on Reactor Safeguards in its letter dated June 10, 1986, were presented. The second supplement (SSER 2) published in January 1987 reported on the status of the unresolved items and indicated those that had been resolved. The third supplement (SSER 3) published in May 1987 reported on the continuing process of resolving the remaining items. Supplement 4 to the SER (SSER 4) documented the resolution of all remaining outstanding open and confirmatory items and license conditions identified in the SER and its supplements and supported the license for initial criticality and power ascension to 5 percent power operation. The present report, Supplement 5 to the SER (SSER 5), provides all documentation necessary to support the issuance of a full-power license.

Each of the following sections or appendices is numbered the same as the corresponding SER section or appendix that is being supplemented. Each section is supplementary to and not in lieu of the discussion in the SER unless otherwise noted. Appendix A continues the chronology of the staff's actions related to the processing of the South Texas Project application. Appendix B lists references other than NRC references cited in this supplement.* Appendix D lists acronyms used in this supplement. Appendix E lists principal staff members and consultants who contributed to this supplement. Appendix Y documents the technical evaluation by EG&G Idaho, Inc., of Revision 2 of the inservice testing program.

Copies of this SER supplement are available for inspection at the NRC Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the local Public Document Room located at the Wharton Junior College Library, Wharton, Texas.

The NRC Project Manager for South Texas Project, Units 1 and 2, is N. Prasad Kadambi. Dr. Kadambi may be contacted by calling (301) 492-1337 or by writing to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

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* Availability of all material cited is described on the inside front cover of this report.

1.12 Items Resolved in Support of Full-Power Licensing

SER Sections 1.7 and 1.8 indicated items that were considered in the staff's review, and SSER 4 provided closure of all items. Table 1.7 lists the issues most recently considered by the staff in support of the full-power license and indicates the section number in which the evaluation is documented.

Table 1.7 Listing of items resolved in support of full-power licensing

Item		Status	Section*
(1)	Onsite meteorological measurements program	Resolved in SSER 5	2.3.3
(2)	Essential cooling pond seepage	Resolved in SSER 5	2.4.11.2
(3)	Recomputation of leak-before-break analyses	Resolved in SSER 5	3.6
(4)	Operability of auxiliary feedwater system	Resolved in SSER 5	3.9.2.1.1
(5)	BMI thimble tubes	Resolved in SSER 5	3.9.2.3
(6)	Inservice testing of pumps and valves	Resolved in SSER 5	3.9.6
(7)	RTD response time	Resolved in SSER 5	4.4.3.2
(8)	Full-flow-filter recovery	Resolved in SSER 5	4.4.8
(9)	Containment isolation system	Resolved in SSER 5	6.2.4
(10)	Use of lifted leads and jumpers during routine maintenance	Resolved in SSER 5	7.8
(11)	Fire protection	Resolved in SSER 5	9.5.1
(12)	Emergency Plan	Resolved in SSER 5	13.3
(13)	NUREG-0737 Item III.D.1.1, Primary Coolant Outside Containment	Resolved in SSER 5	13.5.2.4
(14)	Radiological security	Resolved in SSER 5	13.6
(15)	Limiting conditions for operation and surveillance requirements	Resolved in SSER 5	16.1
(16)	Snubbers - relief from ASME Boiler and Pressure Vessel Code Section XI	Resolved in SSER 5	16.2
(17)	Administrative controls	Resolved in SSER 5	16.3
(18)	Safety injection flow rates	Resolved in SSER 5	16.4
(19)	Turbine overspeed protection	Resolved in SSER 5	16.5
(20)	Diesel generator rotational speed	Resolved in SSER 5	16.6
(21)	Containment tendons surveillance requirements	Resolved in SSER 5	16.7

* Section of this supplement where item is discussed.

2 SITE CHARACTERISTICS

2.3 Meteorology

2.3.3 Onsite Meteorological Measurements Program

In the SER, the staff identified open items related to upgrades in the meteorological measurements program and the measurement of precipitation. To confirm that the meteorological data provided by the new measurement system are of high quality and representative of conditions in the vicinity of the site, the licensee was to provide an additional year of onsite data and an analysis of these data. The licensee provided 6 months of hourly meteorological data from the primary tower for the period May-October 1986, which the staff evaluated and found acceptable as discussed in SSER 4.

The licensee has provided the additional data for the 6-month period from November 1986 through April 1987 and a comparison of data taken from the primary and backup towers. The parameters provided include wind direction, wind speed, atmospheric stability, precipitation, temperature, and humidity. Data recovery for all parameters except humidity and temperature at the 60-m level was well above the 90 percent recommended in Regulatory Guide 1.23, "Onsite Meteorological Programs." During the May 1986-April 1987 period, the 60-m temperature recovery rate was 90.3 percent and the dewpoint recovery rate was estimated to be about 70 percent. In some instances, mostly related to dewpoint measurements, it appeared that some erroneous data had not been edited from the otherwise valid data entries. However, this does not appear to be a significant problem in regard to the overall quality of the data. The staff has reviewed the data for the entire year and compared that data with the onsite data collected from January 1974 through December 1977.

Dates for both periods indicate that the prevailing winds at the 10-m level were from the southeast, south-southeast, and south, occurring together about 30 percent and 41 percent of the time for the May 1986-April 1987 and January 1974-December 1977 periods, respectively. Winds from the west-southwest, west, and west-northwest occurred least frequently with a total frequency of only about 6 percent and 4 percent for the 1986-1987 and 1974-1977 periods, respectively. Similarly, at the 60-m level during the 1986-1987 period, winds from the southeast, south-southeast, and south were most frequent, occurring together about 40 percent of the time, and those from the west-southwest, west, and west-northwest were least frequent with a total frequency of only about 5 percent.

Wind speeds were somewhat lower during the 1986-1987 period, averaging about 3.3 miles per hour (mph) (7.5 m/sec) at the 10-m level and about 5.3 mph (11.5 m/sec) at the 60-m level. Calm conditions (defined as wind speeds less than the starting threshold of the anemometer) occurred about 0.5 percent of the time at both heights. The average wind speed at the 10-m level during the 1974-1977 period was about 4.8 mph (10.7 m/sec). Calm conditions occurred less than 0.2 percent of the time during this 4-year period.

Neutral (Pasquill type D) and slightly stable (Pasquill type E) stability conditions predominated at the site during the May 1986-April 1987 period; each occurred about 31 percent of the time, as defined by the vertical temperature gradient between the 60-m and 10-m levels. Moderately stable (Pasquill type F) and extremely stable (Pasquill type G) conditions occurred about 12 percent and 8 percent of the time, respectively, for the same stability indicator. During the 1974-1977 period, neutral conditions predominated at the site, occurring about 31 percent of the time. Moderately stable and extremely stable conditions occurred about 14 percent and 10 percent of the time during that same period.

The annual total precipitation measured at the site for the 1986-1987 period was 1,248 mm (49.1 inches), with 405 mm (16.0 inches) of this amount occurring during two storms. The annual average precipitation at Victoria, Texas, is approximately 910 mm (35.9 inches).

The licensee has provided a comparison of wind-direction, wind-speed, and temperature data from the primary and backup towers for the 3-month period from August through October 1986. During this period, the wind-direction correlation at the 10-m level was good. Data from the two towers differed by less than 3 percent in the direction of greatest variability. Hour-by-hour comparisons of wind speed and temperature at the 10-m level showed a strong statistical correlation, with Pearson correlation coefficients of 0.94 and greater than 0.99 for wind speed and temperature, respectively.

The staff finds that the May 1986-April 1987 data are of high quality and reasonably representative of conditions in the vicinity of the site for all of the meteorological parameters except dewpoint. As stated in SSER 4, the licensee has made a commitment to take actions necessary to ensure that the subject equipment properly performs its function. The staff will review the dewpoint measurement system as part of the evaluation of the fog monitoring program that will be completed after Unit 2 becomes operational. The staff has also reviewed the comparison and correlation of the meteorological data measured on the primary and backup towers and finds them acceptable. Thus, the staff concludes that the licensee has fulfilled the commitments discussed in SSER 4 related to upgrades in the meteorological measurements program for the key parameters used in making atmospheric dispersion estimates and the measurement of precipitation.

2.4 Hydrologic Engeering

2.4.11 Cooling Water Supply

2.4.11.2 Emergency Cooling Water

The construction permit SER, NUREG-75/075 dated August 1975, contained a requirement for periodic monitoring of leakage from the essential cooling pond (ECP) in order to ensure a 30-day supply of water in the ECP for emergency conditions. This position was reiterated in NRC Question 241.5N during the operating license review. In response to the subject question, the licensee stated that a preestablished periodic seepage monitoring program would not be meaningful because the flow gradient in the vicinity of the ECP will be too small to allow feasible routine measurements, considering the minute volume of water loss due to seepage (0.6 acre-foot/day at a seepage rate of 0.3 ft^3/sec and 2.4 acre-feet/day at a seepage rate of 1.2 ft^3/sec). In addition, the

licensee stated that there is no potential for a sudden or unexpected increase in water loss due to seepage because the impoundment is entirely below ground surface, thereby preventing the opening of flow paths (e.g., those due to piping) to a free surface. The staff agrees in principle with the licensee's conclusion, although it is the staff's position that there is some potential for increased seepage (probably not sudden) due to cracks or other anomalies in the soil cement and concrete side slopes or the portion of the bottom that is natural material. In addition, any significant change in seepage will be a low-probability occurrence.

During its review of this issue, the staff noted (on the basis of a partial hydrograph from one piezometer) that the normal range of groundwater fluctuations in the vicinity of the ECP was between elevations 21 and 25 feet mean sea level (msl). When the pond and groundwater are at the same elevation there is no gradient to drive seepage from the pond. On this basis, the staff suggested that the licensee evaluate the 30-day emergency water supply assuming an initial ECP water level of 21 feet msl. If the licensee can still initiate and maintain shutdown under design conditions, there will be no need for the seepage monitoring. The licensee agreed to do this evaluation.

By letter dated November 12, 1987, the licensee submitted an analysis based on a lower limit groundwater level and a starting ECP level of 21 feet msl. The licensee concluded that there would be a 30-day emergency water supply in the ECP. However, it still committed to perform an annual abbreviated seepage monitoring program. During its review of this analysis, the staff found a more complete piezometric hydrograph, which although inconsistent with those from other piezometers, showed groundwater levels as low as elevation 17.0 feet msl. The licensee was requested to review its more complete piezometric records in the ECP vicinity to verify the lower limit groundwater levels. The review showed that groundwater levels could in fact drop considerably below elevation 21.0 feet msl and that the licensee's analysis was invalid. However, it is anticipated that when the main cooling reservoir is filled to its maximum operating level, the groundwater levels in the vicinity of the ECP will not fall below elevation 20 or 21 feet msl.

Thus, although the analysis of the lowest groundwater level cannot be used individually as a basis to eliminate the seepage monitoring requirement, it does provide positive support for the judgment that increased seepage from the ECP is very improbable, since the groundwater level will probably never fall below about 20 feet msl and if it did it would only be for a short period and be an infrequent occurence.

During a conference telephone call with the NRC staff on December 10, 1987, the licensee suggested an analysis that would show the large area of the bottom clay blanket that would have to be removed or altered to reduce the ECP emergency water supply to less than 30 days. The staff agreed to the approach, since this analysis had already been done by the staff and was the main justification for concluding that potential increases in ECP seepage were not significant concerns at the South Texas site.

By letter dated January 15, 1988, the licensee submitted an analysis that showed that 1.1 acres of the 2-foot clay blanket on the bottom of the ECP

would have to be removed, with subsequent seepage directly to a sandy clay or silt layer, before the minimum 30-day emergency water supply would be affected. In its analysis, the licensee used the following parameters and assumptions:

(1) The ECP is a below-ground reservoir and the only avenue of seepage or flow out of the ECP is to the shallow aquifer.

(2) The piezometric level in the shallow aquifer is assumed to be at +17.0 feet msl. The groundwater level is normally at about 19 to 21 feet msl.

(3) The volume of water loss needed to lower the pond from elevation +25.5 feet to +18.4 feet msl is approximately 305 acre-feet. (The minimum submergence for the service water pumps is 18.4 feet msl.)

(4) Evaporative water loss over a 30-day period is 107 acre-feet and the anticipated seepage loss over the same period is 100 acre-feet based on a calculated seepage loss of 1.2 ft^3/sec. (The actual current seepage loss shown by water balance analysis is about 0.3 ft^3/sec or 24 acre-feet for 30 days.)

(5) The permeability of the shallow aquifer is 1×10^{-3} cm/sec. This is the permeability of the sandy material that covers only about 20 percent of the pond bottom. The silt and clay material that covers 80 percent of the pond bottom has a much lower permeability (1×10^{-5} cm/sec or less).

The combined evaporation and seepage losses over the 30-day period are 207 acre-feet, which would leave 98 acre-feet for unexpected seepage loss over the 30-day period. The licensee used a hydraulic gradient of 1 and a permeability of 1×10^{-3} cm/sec to derive the exposed area of 1.1 acres required to account for the 98 acre-feet of unexpected seepage over the 30-day period. The staff made an independent analysis similar to that of the licensee except for the gradient.

The staff assumed a conservative driving head of 8.5 feet. In reality, the average driving head over the 30-day period would be between 1.4 feet and 8.5 feet, or about 6.0 or 6.5 feet. Using the higher driving head (or gradient), the staff calculated that over 5,900 ft^2 of the 2-foot clay blanket covering the sandy material would have to be removed before the 30-day emergency water supply would be affected by increased seepage loss. Other than a large earthquake well beyond the design basis and coincident with the need for the 30-day emergency water supply, there is no natural occurrence that would remove 5,900 ft^2 of the 2-foot clay blanket or cause 5,900 ft^2 of cracks in the soil cement or concrete side slopes of the pond.

Conclusions

The staff has reviewed boring logs and test pit logs for the ECP. The logs show that the major portion of the pond bottom is composed of extensive, low-permeability, silty clay deposits. A small portion (about 20 percent) of the pond bottom (southeast end) contained silty sand (SM) and clay silt (ML). This material was removed to a 2.0-foot depth and replaced with a 2.0-foot

engineered clay backfill. On the basis of this review and the analysis discussed above, the staff concludes that it is very improbable that the ECP seepage rate will change appreciably over the life of the plant and that seepage monitoring should only be done on an infrequent basis. Regulatory Guide 1.127, "Inspection of Water Control Structures Associated With Nuclear Power Plants," recommends that the inspection (or monitoring) frequency should not exceed 5 years. It is the staff's position that the licensee should perform the abbreviated seepage monitoring program discussed in the November 12, 1987 letter at approximately 5-year intervals. The interval may be up to 6 years to allow the monitoring to coincide with a refueling outage.

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Pipeline

In SSER 4, the staff concluded that the licensee had provided technical justification for not providing devices against the dynamic effects of postulated pipe breaks in the pressurizer surge piping and the accumulator piping at South Texas Units 1 and 2 in support of its request for exemption from a portion of the requirements of General Design Criterion 4 of Appendix A to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR 50).

By letter dated July 16, 1987, the licensee provided its reevaluation of the leak-before-break (LBB) analyses of the accumulator piping using a revised version of the Bechtel structural analysis computer program ME101. The staff has reviewed this submittal and finds that the conclusions in SSER 4 remain valid.

By letter dated September 21, 1987, the licensee submitted Westinghouse report WCAP-11555, which provided another reevaluation of the LBB analyses of the accumulator piping using the final documented loads. The staff compared the loads in Tables 5-1 through 5-3 of WCAP-11555 with the loads in Table 1 of Attachment 2 to the licensee's letter of July 16, 1987 and determined that the small changes in loads (less than a 1 percent increase) would not affect the results of the LBB analyses. Thus, the staff finds that the conclusions in SSER 4 remain valid with respect to these areas of review.

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

3.9.2.1 Piping Preoperational Vibration and Dynamic Effects Testing

3.9.2.1.1 Operability of the Auxiliary Feedwater System

Recently several hydraulic transient events occurred in the auxiliary feedwater (AFW) system and main feedwater (MFW) system of South Texas Unit 1.

On November 5, 1987, a 1-inch vent line with two vent valves broke off the AFW pump discharge line in train A. The plant was in mode 4 and the system was in operation to support steam generator blowdown testing. On November 8, 1987, while the system was under the same flow conditions, a second failure occurred in a double valve instrument tap for the train D flow element. On November 14, 1987, the licensee initiated a steady-state vibration test program to confirm that the cause of the failures was fatigue cracking, which was believed to be the case at the time. Shortly after the test was started, a cracked anchor was found downstream of the train A crossover isolation valve. A temporary support was installed near the cracked anchor and the vibration test was continued.

On November 15, 1987, while the vibration test was being continued, a waterhammer occurred in the system when the crossover isolation valves from train A to train D were being opened. This event led the licensee to believe that air entrapment in the system was the cause of vibration that resulted in the failures. As a corrective measure, five additional high point vents were installed. A revised venting procedure was established which consisted of a dynamic sweep of the crossover line to ensure that all air was removed from the system. An additional test was then successfully performed to demonstrate that a water solid system would not experience a waterhammer because the crossover isolation valves were being opened under no-flow conditions. The plant was permitted to enter into mode 3 on November 21, 1987.

On November 22, 1987, shortly after the plant entered mode 3, sustained piping vibration in trains A and C was observed, resulting in additional support failures. Several tests were performed to try to identify the exact cause of, and possibly reproduce, the above sustained vibration. Multiple steam generator feed tests conducted on December 6 and December 9 induced sustained vibrations. In both cases, the vibration occurred while one pump was running (train B), the crossover isolation valves were open (on December 9 the C and D valves had been closed but were just opened), and the flow control valves were highly throttled at their near-seat position. A review of test data showed that the system was being subjected to a sustained vibration having a frequency of 24 Hz.

A series of tests was performed on December 12 to determine which component was producing the 24-Hz excitation. The test systematically isolated the source of excitation to be the train A flow control valve in a near-seat (highly throttled) position coupled with the train D flow control valve in a near-seat position. The test also showed that the throttling position of the train B and C flow control valves, the use of the pump, and the crossover valves had no effect on the resonant condition. The resonance terminated when the train A and D flow control valves were lifted off their near-seat positions.

On January 11, 1988, with Unit 1 in mode 5, three hydraulic transients occurred while steam generators A, B, and C were being filled with main feedwater as a source of water supply. The main feedwater is preheated with a full-flow dearator.

During initial filling operations, feedwater was recirculating to the condenser so that a feedwater temperature of approximately 290°F could be maintained. The steam generator temperatures were approximately 180°F.

An operator was stationed in the isolation valve cubicle (IVC) before the initiation of feedwater flow to steam generator C. A valve lineup was performed to initiate feedwater flow to the upper nozzle via the preheater bypass line. The preheater bypass line is the crosstie between the main feedwater and the auxiliary feedwater piping to the upper nozzle. The feedwater bypass control valve (FBCV) was shut and flow was then established to the steam generator by opening the feedwater preheater bypass valve (FPBV) and throttling open the FBCV. The stationed observer noted a slight clicking of the check valve donwstream of the FPBV but no piping vibration.

The reactor operator proceeded to fill steam generator B in the same manner. The stationed observer reported noise and vibration in the preheater bypass and auxiliary feedwater lines after flow was established.

Flow was secured and the hydraulic transient was terminated. The same procedure was repeated for steam generator B. Additional observers from the control room in the IVC noted no noise and/or vibration. The same sequence was then performed to fill steam generator A and vibration and noise were reported. Flow to steam generator A was secured and the hydraulic transient was terminated. Flow to steam generators B and C was then secured. Recirculation flow was also secured at this time.

It was then decided to fill steam generator C by using the main feedwater line to the lower steam generator nozzle. The FBCV was shut and the feedwater isolation bypass valve was opened. The FBCV was throttled open to establish flow. Noise was heard, flow was secured, and the transient was terminated.

Evaluation of the Original Events

In its submittals of December 24, 1987 and January 18, 1988, the licensee presented its root cause finding, the proposed corrective actions, and the proposed confirmatory tests for all the above AFW/MFW transient events. The staff has reviewed these documents together with the additional information presented by the licensee in the meeting held on December 2, 1987, in Bethesda, MD, and found them generally acceptable. The staff and its consultants from Brookhaven National Laboratory (BNL) also conducted a series of plant site inspections on November 18-20, 1987, January 20-21, 1988, January 25-30, 1988, and February 10-12, 1988. During each of the site inspections, supplemental technical information was reviewed, and walkdowns were conducted on the portions of the systems involved. As-built configurations of the components and supports conformed with the design drawings. Hardware repairs, modifications, and additions as observed in the plant corresponded to the requirements called for by the corrective actions. During the plant inspection on January 25-30, 1988, the BNL consultants also witnessed a portion of the confirmatory testing conducted on the AFW and MFW systems. These findings constitute a partial basis for the staff's conclusion in this report.

(1) AFW Transients

The AFW hydraulic transients were of two distinct types: short-duration waterhammer events and longer-duration vibration events. Because of the nature of the earlier events, it was first thought that air in the system was the cause of the waterhammers. After installation of additional high point vents and a revision to the venting procedure, the air-induced waterhammer problem was resolved. However, the system continued to experience vibration. Subsequent testing and investigation led to the identification of the cause of the vibration. When the flow control valves from trains A and D were in a highly throttled position, they were found to generate a hydraulic pressure fluctuation, the dominant frequency of which (24 hz) matches one of the natural frequencies of the portion of the piping system. The system, therefore, exhibits a very rare combination of both hydraulic and structural resonance. As a result, the magnitude of the vibrations was large enough to cause the damage observed.

Vent assembly connections and pipe support damage caused by the hydraulic transient events have been repaired. All required support modifications have also been completed. Nondestructive examinations that were repeated following completion of these repairs and additional testing have confirmed the integrity of the piping and supports.

(2) MFW Transients

Steam condensation was determined to be the cause of the main feedwater hydraulic transients. Because of the lower steam generator back pressure, a two-phase flow condition resulted when the feedwater pressure dropped below the saturation pressure corresponding to the feedwater temperature.

When the feedwater was fed through the steam generator upper nozzles of trains A and B, the hydraulic transients occurred because the steam in the two-phase flow displaced the stagnant cold water in the vertical auxiliary feedwater lines, causing a series of steam bubble collapses. When steam generator B was fed the second time, no hydraulic transient occurred. At this point, according to the licensee, the vertical auxiliary feedwater line had already been purged of cold water.

In the case of train C where the AFW line runs horizontally to the main header, the very limited volume of cold water in AFW piping that could have mixed with the two-phase flow in the 8-inch header had been purged along with cool water from the main flow path that had been initially purged. Therefore, no noise or vibration was observed while train C was fed through the preheater bypass line.

On the other hand, while the feedwater was fed through the train C steam generator lower nozzle, a hydraulic transient occurred when the feedwater isolation bypass valve (FIBV) was opened and flow was established by throttling the feedwater bypass control valve. Opening the FIBV injected hot water into a relatively small volume between the feedwater isolation valve and the downstream feedwater check valve. Steam and thus a two-phase flow condition probably started to form when the water was heated to the saturated temperature corresponding to the pressure in the pipe. This caused a high volumetric flow rate that opened the check valve and allowed the cold water from downstream to mix with the two-phase flow. The steam condensed, which, in turn, resulted in a rapid decrease in pressure upstream and, consequently, slammed shut the check valve. The steam condensation plus the rapid closure of the check valve resulted in the hydraulic transient.

The staff found the above event descriptions and root cause findings presented by the licensee acceptable. (See section entitled "Confirmatory Actions" below.) The staff also agrees with the licensee that the MFW events had no relationship to the AFW transient events that occurred earlier.

Corrective Actions

As stated previously, corrective actions were undertaken by the licensee to eliminate the recurrence of AFW waterhammers and MFW hydraulic transient events.

(1) AFW Transients

For AFW transients, the corrective actions included the following:

(a) The existing venting procedures were modified to add a dynamic sweep of the crossover line to ensure that all air was removed from the system, thus preventing the possibility of air-induced waterhammers.

(b) Mechanical stops were installed on the flow control valves. This together with the adjustment of the limit switches will ensure that these valves cannot be positioned so that flow would be less than 50 gpm, thus avoiding the 24-Hz resonance condition.

(c) The seat rings of the train A, C, and D flow control valves were machined to create expansion chambers comparable to those in the train B flow control valve.

(d) The air diaphragm operators on the train A, B, and C crossover valves have been replaced, using stiffer springs, to provide an additional hydraulic stability margin to the AFW system. New baseline data also were obtained for these valves and were incorporated into the appropriate surveillance test procedures.

(e) A needle valve was installed in the air operator of the train D crossover valve to increase its opening stroke time.

(f) Five additional high point vents were installed for facilitating removal of air trapped in the system.

(g) A number of the piping supports have been modified and additional supports added to the crossover piping header.

According to a February 19, 1988 submittal, design change documents have also been issued to make all of the above modifications part of the design of South Texas.

(2) MFW Transients

For the MFW hydraulic events, the revised plant operating procedures were reviewed to determine how the limitations on the use of main feedwater were implemented. The limitations appear as precautionary notes in the plant heatup procedure (IPOP03-ZG-0001) and the secondary plant startup procedure (IPOP03-46-0003) and as a specific procedural statement in the plant cooldown procedure (IPOP03-ZG-0007). The precautionary statement is: "Do not feed Steam Generators with the Main Feedwater system until S/G temperature is greater than 340°F." The staff found this action to be acceptable.

During the site inspections, the staff and the BNL consultants reviewed and further verified the above corrective actions.

Confirmatory Actions

Several confirmatory actions have been undertaken by the licensee to ensure that no similar waterhammers or hydraulic transients would occur again in the

AFW and MFW systems after completion of the previously stated corrective actions.

(1) AFW Transients

For the AFW system, the confirmatory tests include the following:

(a) Crossover Isolation Valve Static Stroke Test

Once new air operators were installed on trains A, B, and C and internal valve work was completed, an auxiliary feedwater system valve operability test was performed. This test established new baseline data for opening and closing times of the crossover isolation valves. The results showed that the opening times ranged from 10.8 seconds for the train D valve to 23.2 seconds for the train A valve, which were then used as the reference opening stroke times for the subsequent series of tests. The closing time ranged from 3.8 seconds for the train D valve to 5.7 seconds for the train C valve, all within the 10-second valve-closure design criterion.

(b) Crossover Isolation Valve Full-Flow Testing

Valve operability testing under full-flow conditions was conducted on train A, B, and C crossover isolation valves after operators with stiffer springs were installed. The test consisted of opening and closing the crossover valves with a flow of 650 to 675 gpm through the associated test line and recording the closure stroke time of the crossover valve. The design criterion of valve closure within 10 seconds was met. No excessive vibration or waterhammer was observed.

For the crossover valve on train D, equipped with a needle valve, the opening stroke time increased from the previous 2 to 3 seconds to around 7 to 10 seconds, which is considered normal as compared with the above reference stroke time obtained under Item (a). The design criterion of 10-second closure time was also met. No excessive vibration or waterhammer occurred during the opening or closing of the valve.

(c) AFW Motor-Driven Pump Performance Test

Pump surveillances were performed to ensure that no degradation of the pumps had occurred. These test results were compared with the previous motor-driven AFW pump surveillance test results and showed no indications of abnormal pump degradation.

(d) Flow Control Valve Testing - Mode 4 - Multifeed

This test was conducted after machining of the valve seats of the A, C, and D flow control valves, the installation of the mechanical stops, and the changing of limit switch settings. The test consisted of physically closing each train's flow control valve hard against the mechanical stop and then opening the containment isolation valve to establish flow to that train's steam generator. The magnitude of pressure pulses between 0 and 100 Hz was examined with special emphasis at and around 24 Hz. Test pressure data were taken from transmitters installed upstream and downstream of the flow control valves. Data were first analyzed for the flow control

valve closed hard against the mechanical stop. The valve was then incrementally opened with the handwheel, and data were evaluated at each step. This process was repeated until the flow rate through each flow control valve was 160 gpm or more.

In all instances, the modified valve pressure pulsations at or around 24 Hz were insignificant and no abnormal dynamic response was generated.

(e) Flow Control Valve Testing - Mode 4 - Single Train

The test was conducted to examine the pressure pulse amplitudes from 0 to 100 Hz for simultaneous feeding of all four steam generators. It employed the train B auxiliary feedwater pump and the system crossover valves. Flow was established to all four steam generators with each flow control valve manually closed against its mechanical stop. Flow was then increased to each steam generator by approximately 20 gpm. This process was continued until the flows simultaneously to all four steam generators were 160 gpm or more.

At each change of steam generator auxiliary feed flow, the pressure data upstream and downstream of each flow control valve were analyzed. Pressure pulses were insignificant at or around the 24-Hz frequency, and no abnormal dynamic response was generated.

(f) Flow Control Valve Testing - Mode 3 - Multifeed

The test described under Item (d) was repeated with the plant in operational mode 3 at normal operating pressure and temperature. The peak pressure pulses at or near 24 Hz were insignificant, and no abnormal dynamic response was generated.

(g) Flow Control Valve Testing - Mode 3 - Single Train

The test as described under Item (e) was repeated with the plant in operational mode 3. The peak pressure readings obtained were insignificant, and no abnormal dynamic response was generated.

(h) Flow Control Valve Testing - Turbine-Driven Pump - Mode 3 - Multifeed

The pressure pulsations between 0 and 100 Hz upstream of the flow control valves of all auxiliary feedwater trains were examined with flow provided by the turbine-driven train D AFW pump. Again, as in the mode 4 multifeed motor-driven tests, the data were analyzed at each change of flow rate. The first data point was for all valves against the mechanical stops. Flow was incrementally increased up to a flow rate of 160 gpm to each steam generator. Special attention was given to pressure pulsations near 24 Hz.

The peak pressure pulses at or near 24 hz were insignificant, and no abnormal dynamic response was generated.

(i) AFW System Safety Performance Test

Tests were conducted to demonstrate that upon engineered safety features actuation, the motor-driven AFW pumps would start, and regulating valves would control flow in both the automatic and manual modes without inducing unacceptable transients in the AFW system. These test were completed while the system pressure was being monitored and observers were in the IVCs. No abnormal pressure transients or abnormal vibrations were experienced for any of the motor-driven pumps, and no abnormal dynamic response was generated.

The above confirmatory tests have been reviewed by the staff and were found to be consistent with the independent observations made by the BNL consultant during portions of the testing.

(2) MFW Transients

For MFW hydraulic transients, confirmatory tests were conducted during operational modes 3 and 4 to verify that feeding the steam generators with main feedwater in accordance with revised plant operating procedures would not result in adverse hydraulic transients.

Each steam generator was fed through the upper nozzle by opening the feedwater preheater bypass valve (FPBV) for the first test, and through the lower nozzle by opening the feedwater isolation bypass valve (FIBV) for the second test. Auxiliary feedwater flow to the applicable steam generator was secured before feeding with main feedwater. The warmup recirculation flow that had been established previously was secured before each test.

Observers were stationed in the IVC at the piping areas subject to the hydraulic transients to record any evidence of damage, noise, or vibration before, during, and after each test. The applicable plant conditions were recorded before, during, and after each test. Data consisting of pressure readings were obtained at the drain valves downstream of the intersection of the preheater bypass line to the AFW line.

As would be expected, when feeding through the upper nozzle, vibration did not occur while the train C steam generator was being fed. It did occur, however, in the initial attempts at feeding the train A and B steam generators. Again, it was determined to be due to the difference in the piping configurations at the interface of the AFW and MFW system as stated previously.

In the second case, when feeding train C through the FIBV to the lower nozzle, the operators noted that a "banging" noise started several minutes after the valve was opened. They also heard the noise repeating at roughly 10-second intervals thereafter (during the brief period before the valve was closed).

The licensee has also performed a supplemental analytical calculation to confirm the above periods of time observed in the tests. First of all, the time required to increase the temperature of the water between the feedwater isolation valve and the feedwater check valve to the point of flashing was estimated. Various simplifying assumptions, such as neglecting the heat capacity of the

pipe and valves, were included in this calculation. The result was a period of at least 100 seconds required. This compares with the computer records that show that the FIBV was open for 3 minutes and 13 seconds, which allowed sufficient time for heatup of the water plus several steam bubble collapses.

The period of repetition was calculated in a similar manner. The degree of subcooling present immediately following one steam bubble formation and collapse cycle was calculated by replacing the volume of the steam bubble formed upstream of the check valve with downstream cooler water. The calculated time between cycles was 9.4 seconds, as compared with about 10 seconds as observed.

The staff has reviewed the above calculation and found it was generally adequate, with the following exception. There was no explanation as to how cold water from downstream of the check valve could mix with the steam bubbles forming upstream once the valve was opened by a high volumetric flow rate from upstream of the valve. This is not considered to be significant, however, as the exact process of mixing between the cold water and the two-phase flow and the subsequent collapsing of steam bubbles can at best be qualified by conjecture at this time without experimental testing.

The staff has determined that the information provided by the licensee for the above confirmatory tests and analyses is acceptable and consistent with the observations made by the BNL consultants during a portion of the testing.

As requested by the staff during the February 10-12, 1988 plant inspection, the licensee has also reviewed the emergency operating procedures (EOPs) to determine if they prescribe the use of main feedwater during emergency conditions and if this use could establish the conditions necessary for the observed feedwater hydraulic transient. In the February 19, 1988 submittal, the licensee states that the only instance where the EOPs do prescribe the use of main feedwater is in the procedure titled "Response to Loss of Secondary Heat Sink." Steps in this procedure direct the operator to attempt to establish main feedwater. However, since this procedure is employed on a loss of secondary heat sink, it is highly improbable that main feedwater will be used when steam generator temperature is below 340°F. The staff finds the above explanation acceptable and agrees that modification of the existing EOPs is not necessary. On the basis of this and all of the confirmatory testing performed, the staff also agrees that no physical changes to piping at the tie-in point of the preheater bypass line to the auxiliary feedwater line (vertical to horizontal) in trains A, B, and D are required.

Conclusion

On the basis of the above evaluation, the staff believes that the licensee has presented sufficient evidence to support its contention that the causes that led to the hydraulic transient events in AFW and MFW systems have been eliminated. This is based on the licensee's efforts in regard to root cause finding, corrective actions, as well as confirmatory analyses and tests. The staff, therefore, concludes that full-power operation at South Texas Unit 1 can be permitted.

3.9.2.3 Preoperational Flow-Induced Vibration Testing of Reactor Internals

Wear of bottom-mounted instrument (BMI) thimble tubes has been observed in a number of pressurized water reactor (PWR) plants. The most severe cases have recently been experienced in a number of European plants. In response to NRC requests to address the potential wear of thimble tubes at the South Texas plants, the licensee indicated that a study concluded that wear of the BMI thimble tubes was caused by vibration resulting from high flow velocity in the BMI column gap. The problem is more severe in 14-foot-core reactors because the flow velocity is higher than it is in 12-foot-core plants. The licensee proposed to reduce this velocity in the 14-foot core at South Texas, Units 1 and 2, to a velocity similar in magnitude to that in the 12-foot-core plants. To accomplish this, a Westinghouse-designed flow-limiting device was installed for each thimble on the lower core support plate in the region between the support plate and the fuel assembly. Similar devices had been installed in several European 14-foot-core plants. In addition, because the inside diameter of the BMI column is larger in Unit 1 than in Unit 2, a sleeve was installed around the Unit 1 thimble so that the gap size would be identical to that of Unit 2. The sleeves and flow-limiting devices were installed before fuel was loaded. Detailed sketches of the proposed changes were submitted by the licensee in a letter dated December 19, 1986.

On ths basis of its review of the information provided by the licensee, the staff concluded that the design changes provided reasonable assurance that the wear problem at South Texas, Units 1 and 2, would be minimized (SSER 4). Because similar design changes had been implemented at European 14-foot-core plants and because the licensee had committed to monitor the performance of these plants relative to this issue including sample inspection of the flow-limiting devices and BMI thimbles during the first refueling outage to ensure that the wear problem would not recur, the staff had concluded that this should be a confirmatory issue pending documentation of conclusive data that verify that BMI thimble tube wear has been corrected.

On October 23, 1987, a Belgian plant, Tihange 3, which has a 14-foot core and where the same Westinghouse flow-limiting devices as those at South Texas had been installed, experienced BMI thimble leakage after only 4 months of operation. This event raised further questions regarding the adequacy of the flow-limiting devices in resolving the wear problem.

To learn more about European experience with the BMI thimble tube wear problem, the staff visited the Tihange plant and held meetings with Belgian and French regulatory authorities. During these meetings, the staff learned that the French had conducted extensive flow tests and determined that thimble tube wear is caused by flow-induced vibration. The vibration is affected by parameters such as axial flow rate and velocity through the gap between the thimble and its guide, the gap size, the pressure differential across the core support plate, the moment of inertia of the thimble, and the flow path geometry. Discussions with Belgian authorities and Tihange plant staff indicated that the Belgians agree with the French regarding the cause of thimble tube wear. In addition, judging from the wear locations, they are concerned that the flow-limiting devices may have either caused or contributed to the problem.

The staff met with the licensee and Westinghouse representatives on November 20, 1987 to further discuss the European findings and their applicability to the South Texas plant. It was learned that South Texas and Tihange 3 were nearly identical in parameters affecting thimble wear. The licensee committed to perform further investigations and provide a report to the staff.

The licensee and Westinghouse representatives met again with the staff on December 14, 1987. Their findings and commitments for corrective actions are summarized in a letter dated January 5, 1988. On the basis of its review of the European data, the licensee could not conclusively determine the reason for the Tihange 3 BMI tube failure. It pointed out the similarities and differences between the two designs. It noted that one difference that may have adversely affected the performance of the flow limiters was that during their installation, Tihange was required to implement a field modification of the flow limiters because of interfering fillet welds on the lower core support plate. This interference was found when the devices were being installed under water using a special long-handled tool. The subsequent installation was verified by camera inspection under water. At South Texas, no field modifications were necessary. The limiters were installed by hand, all work was performed dry, and the fit was verified visually by feeler gage.

To provide further confidence that safety will not be compromised, the licensee committed to implement the following program:

(1) Before Criticality

The licensee performed a baseline eddy current inspection of the BMI thimbles on December 18-24, 1987, after approximately 4 weeks of low-temperature reactor coolant pump operation. No thimble tube degradation exceeding the threshold level of 0.0039 inch was observed.

(2) After Criticality

The licensee will perform another eddy current inspection of the thimbles after 12 weeks of four-pump operation at reactor coolant system normal operating temperatures. BMI thimbles will be repositioned, if necessary, to shift any worn locations out of this wear area, and the need for future eddy current inspection will be assessed.

(3) At Unit 1 Refueling

(a) During the first refueling of Unit 1, the licensee will install remotely operated isolation valves on the BMI tubes. These normally closed valves will form a second barrier to primary system leakage should a BMI tube leak occur. A leak detection device will also be installed ahead of this valve.

(b) The licensee will investigate the installation of heavier wall thimbles at Unit 1. If proven acceptable, these thimbles will be installed by the first refueling.

(c) The licensee will perform a sample inspection of the flow-limiting devices at the first refueling.

Before fuel loading of Unit 2, automatic isolation valves and leak detection devices will be installed. Heavy wall thimbles, if proven successful at Unit 1, will also be installed at Unit 2.

Since the present BMI system does not have any means of isolating BMI thimbles, if thimble tube leakage should occur, the licensee has procured a tube crimping unit, a freeze seal apparatus, and thimble caps. A procedure was prepared for maintenance personnel to enter the area and isolate a thimble should a leak occur.

After a staff request for additional information, the licensee provided the following responses and made additional commitments in a letter dated February 3, 1988:

(1) If any thimbles show wear exceeding 60-percent wall thickness following 12 weeks of operation, those thimbles will be capped. Any remaining thimbles showing significant wear will be repositioned to shift any worn location out of the wear area.

(2) The licensee provided the results of a calculation on the leakage flow rate resulting from a failed BMI thimble tube. The results supported the licensee's contention that the thimble tube failure issue is a safety concern only if more than three tubes are severed simultaneously because each of the two charging pumps has sufficient capacity to make up the leakage from up to three tubes.

(3) The licensee committed to provide the results of the next Tihange 3 inspection of BMI thimbles to the NRC staff if the results are commercially available.

On the basis of its review of information provided by the licensee and Westinghouse, review of European plant experience, and licensee commitments documented in the January 5 and February 3, 1988 letters, the staff concludes that the potential BMI thimble tube wear will not adversely affect the safe startup and operation of the South Texas plants. This conclusion is based on the following reasons:

(1) Single-tube failure would result in low leakage and may not be a safety concern. The probability of simultaneous multiple-tube failures with leakage exceeding the charging pump capacity is judged to be extremely low.

(2) The licensee has performed a baseline eddy current inspection of the thimbles and will repeat the inspection after 12 weeks of operation. It is highly improbable that a tube failure will occur during this short period.

(3) In the event of tube failure, the licensee has made temporary provisions for thimble tube isolation.

(4) The licensee has committed to take corrective actions if significant wear is observed after 12 weeks of operation.

(5) The licensee has committed to make long-term permanent modifications to isolate possible future leakages and will continue to investigate the long-term resolution of the problem.

Although the staff does not believe that there is any conclusive evidence to prove that the flow-limiting devices at Tihange 3 caused the thimble tube failure, the design similarities with South Texas are an issue of concern. The licensee's theory that the Tihange installation method and field modifications may have adversely affected the performance of the flow limiters is reasonable but as yet unverified. The Tihange event raised questions regarding the adequacy of the flow limiters as a long-term solution to the BMI thimble tube wear problem. Close monitoring of tube wear at South Texas is necessary to verify the effectiveness of the flow-limiting devices.

The staff will continue to evaluate the long-term resolution of this problem by performing the following activities:

(1) It will review the results of the South Texas eddy current inspection program to assess the adequacy of the licensee's evaluation and corrective actions and the possible need for more frequent inspections.

(2) It will monitor the progress of the licensee's program and of Westinghouse studies and test programs for long-term resolution of the thimble tube wear problem.

(3) It will review the results of the next Tihange 3 inspection, if available, and will monitor the progress of the European programs in regard to long-term resolution.

Conclusions

The staff concludes that the licensee has taken appropriate actions to provide a high degree of confidence that the potential BMI thimble tube wear problem will not adversely affect the safe startup and operation of the South Texas plants. However, to ensure safe long-term plant operation, the staff will continue to review and evaluate thimble tube wear inspection results, the licensee's corrective actions, and both plant-specific and generic long-term resolution programs.

3.9.6 Inservice Testing of Pumps and Valves

Technical Specification 4.0.5 for South Texas Unit 1 states that inservice inspection of American Society of Mechanical Engineers, Boiler and Pressure Vessel Code (ASME Code) Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Code and applicable addenda as required by 10 CFR 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55 (g)(6)(i). Certain requirements of the applicable Code edition and addenda of Section XI are impracticable because of certain plant system and component designs.

10 CFR 50.55(g)(6)(i) authorizes the Commission to grant relief from these requirements once it makes the necessary findings. This section contains NRC staff's findings with respect to granting or not granting relief requests submitted as part of the licensee's inservice testing (IST) program.

In SSERs 2 and 4, the staff found acceptable the licensee's first 10-year IST program, Revision 1. The licensee submitted Revision 2 of this program by letter dated October 22, 1987, and provided additional information on the revision during conference calls held on December 2, 3, and 14, 1987. By letter dated February 5, 1988, the licensee submitted Revision 3 of this program.

Revision 2 of the IST program included revised valve tables for limiting values of full-stroke times applicable to power-operated valves, the addition of seven relief requests, the deletion of two relief requests, two amended cold shutdown justifications, and the addition or deletion of certain valves from the program because of design modifications. Revision 3 was prepared primarily to address several deficiencies identified by the staff in its review of Revision 2. The program for the first 10-year interval is based on the requirements of the 1983 Edition through the Summer of 1983 Addenda of the ASME Code, and these requirements will remain in effect through the first 120-month interval of commercial operation.

Revison 2 of the IST program including the requests for relief from the requirements of ASME Code Section XI that have been determined to be impracticable, the amended justifications for testing certain valves at cold shutdown, revised valve tables for limiting valves of full-stroke times, deletion of two relief requests, and the addition or deletion of certain valves from the program was reviewed by the staff's contractor, EG&G Idaho, Inc. (EG&G). The Technical Evaluation Report (TER) provided in Appendix Y is EG&G's evaluation of Revision 2 of the IST program.

In the TER, EG&G also identified several deficiencies and inconsistencies in Revision 2 of the IST program. These items are contained in the evaluation of Relief Request RR-7 in the TER and in Appendix A of the TER. These deficiencies were communicated to the licensee in conference calls on the dates indicated above. Revision 3 contains material that addresses the deficiencies listed in the TER, including a revision of Relief Request RR-8, and contains certain other minor technical changes. The staff has evaluated these changes and determined that the deficiencies have been satisfactorily addressed and that the other technical changes are acceptable. The staff's evaluation of revised Relief Request RR-8 is provided below.

Relief Request: The licensee has requested relief from the requirements of Section XI, Paragraph IWP-3300, for the annual measurement of pump bearing temperatures for all pumps in the IST program and proposes to measure pump vibration velocity quarterly except for the centrifugal charging pumps, for which the licensee proposes to measure pump vibration amplitude quarterly.

Licensee's Basis For Requesting Relief: The yearly measurement of temperature will not provide significant information about pump conditions. Industry experience has shown that the changes in bearing temperature caused by degrading bearings occur only after major pump degradation; the measurement of vibration would provide the necessary information to warn of an impending malfunction. Elimination of this measurement will not have a significant effect on pump evaluation because vibration amplitude is measured quarterly. As an alternative, vibration velocity, as described in Relief Request RR-7, will be measured quarterly in lieu of measuring bearing temperature for all pumps that would require the

measurement of bearing temperature per Paragraph IWP-4310 except for the centrifugal charging pumps. The centrifugal charging pumps, because of ALARA (as low as is reasonably achievable) considerations, will have vibration measured quarterly using remote instrumentation that will only measure displacements caused by vibration.

Evaluation: The licensee has proposed to eliminate the annual measurement of pump bearing temperature for all pumps in the IST program and to measure pump vibration velocity quarterly except for the centrifugal charging pumps.

Experience has shown that when serious degradation of pump bearings occurs, bearing temperatures remain relatively constant until just before the actual bearing failure. With the bearing temperature being measured on an annual basis, the likelihood of detecting a bearing failure during the test is minimal. Elimination of the requirement to measure bearing temperature would not affect the effectiveness of the pump monitoring program.

The accuracy of the bearing temperature measurement is affected by variations in the temperature of the fluid passing through the pump. This variation in fluid temperature complicates the analysis of the trends of the bearing temperatures from year to year.

In many cases, the licensee is burdened by the lengthy run time needed to take three successive bearing temperature measurements because of plant or system design limitations.

On the basis of the determination that the measurement of bearing temperature provides little meaningful data, is a burden to the utility, and does not contribute significantly to the effectiveness of the pump monitoring program, relief from measuring bearing temperature should be granted.

The staff has reviewed the TER and agrees with its evaluations and conclusions. The relief request determinations, including the staff's revised evaluation of Relief Request RR-8, and cold shutdown justifications are summarized in Table 3.1. The granting of relief is based on the fulfillment of any commitments made by the licensee in its basis for each relief request and the alternative proposed testing.

Conclusion

On the basis of its review of the IST program, Revisions 2 and 3, the staff concludes that the program as evaluated will provide reasonable assurance of the operational readiness of safety-related pumps and valves to perform their safety-related functions. The staff has determined that, pursuant to 10 CFR 50.55a(g)(6)(i), granting relief if the Code requirements are impracticable is authorized by law and will not endanger life or property or the common defense and security. The staff also has concluded that granting relief is in the public interest considering the burden that could result if the requirements were imposed on the facility. The IST program for South Texas submitted by letter dated February 5, 1988, is acceptable for implementation. Relief requests contained in any subsequent revisions may not be implemented without prior approval by the NRC staff.

Table 3.1 Summary of relief requests

Relief request number	TER section	Section XI requirement and subject	Equipment identification	Alternative method of testing	Action by NRC
Pump RR-5	1.1.1	IWP-4120 Full-scale range of instruments	All pumps in IST program	Use portable instruments that exceed three times the reference value with repeatability per Table IWP-4110-1.	Relief granted
Pump RR-6	1.1.2	IWP-4120 Full-scale range of instruments	Chemical and volume control system (CVCS) pumps P1A and P1B and residual heat removal (RHR) pumps 1A, 1B, and 1C	Use installed on-line vibration monitoring equipment that may exceed three times the reference valve with repeatability per Table 1WP-4110-1.	Relief granted
Pump RR-7	1.2.1	IWP-4120 Measure pump vibration amplitude	All pumps except RHR and CVCS centrifugal charging pumps	Use pump vibration velocity measurements as outlined in Unit 1 IST program.	Relief granted provided measurements are taken as discussed in TER Section 1.2.1
Pump RR-8	1.3.1	IWP-3300 Measure pump bearing temperature	All pumps in IST program	Measure pump vibration amplitude quarterly in accordance with Code requirements.	Relief granted
Valve RR-46	2.1.1	IWV-3300 Verify remote valve position indication	AP-FV-2455 and 2455A	Verify remote position indication accuracy based on system response to valve position changes.	Relief granted
Valve RR-48	2.2.1	IWV-3521 Test frequency	XSI-0005A 0005B, 0005C 0030A, 0030B, and 0030C	Perform partial-stroke exercise quarterly and full-stroke exercise during refueling outages with reactor vessel head removed.	Relief granted

Table 3.1 (Continued)

Relief request number	TER section	Section XI requirement and subject	Equipment identification	Alternative method of testing	Action by NRC
Valve RR-21	3.1.1	IWV-3411 Test frequency	FCV-0551, 0552, 0553, and 0554	Verify by partial-stroking quarterly, by proper operation of the steam gener ator level system, and by full-stroking at cold shutdown.	Cold shutdown justifica-tion acceptable
Valve RR-32	3.2.1	IWV-3521 Test frequency	XSI-0010A, 0010B, and 0010C	Perform full-stroke exercise during cold shut downs utilizing RHR system flow	Cold shutdown justifica-tion acceptable

4 REACTOR

4.4 Thermal-Hydraulic Design

4.4.3 Design Abnormalities

4.4.3.2 Crud Deposition and Flow Uncertainty

In a letter dated November 12, 1987, the licensee indicated that the resistance temperature detector (RTD) response time for South Texas Unit 1 was longer than that specified in the Technical Specifications. Therefore, the licensee proposed that the Technical Specifications be modified to show an increase in RTD response time from 6.5 seconds to 8.0 seconds. The letter included the proposed Technical Specification changes, revised pages of the Final Safety Analysis Report (FSAR), and the reanalysis of FSAR Chapter 15 accidents affected by the increase in RTD response time.

South Texas Unit 1 is the first plant where a change in the method of measuring the hot and cold leg reactor coolant temperatures has been implemented. The method originally proposed for the plant used a RTD bypass system that was designed to address temperature streaming in the hot legs and, by use of shutoff valves, to allow replacement of the direct immersion narrow-range RTDs without draindown of the reactor coolant system (RCS). Three sampling scoops in each hot leg obtained a flow sample that was measured in an external manifold to obtain an average hot leg temperature. At the South Texas plant the old RTD bypass system was not used; instead, the new RTD thermowell system was installed. The staff review of this change is described in SSER 2. Since the South Texas plant was still under construction when the new RTD thermowell system was installed, the scoops used in the former method were not in place nor were they required.

Although the new system has advantages over the old system, such as improved availability and reduced maintenance and radiation exposure, it also has the disadvantage of a slightly longer response time. Recent tests indicate that the RTD response time is greater than the 6.5 seconds specified in the Technical Specifications.

The staff questioned the licensee regarding the increase in RTD response time. NUREG/CR-4928 "Degradation of Nuclear Plant Temperature Sensors," June 1987, which was issued after SSER 2, provided additional information on the degradation of RTDs. Therefore, the staff requested additional information regarding the uncertainty effects of the new RTD system. The licensee responded to the staff's request by letters dated December 1 and 23, 1987.

RTD Response Time

The overall response time of the new thermowell RTD temperature system as given in SSER 2 was 0.5 second longer than that of the originally proposed RTD bypass system (6.5 seconds vs 6.0 seconds). Recent tests for South Texas Unit 1 have

indicated that the total response time is actually longer. Therefore, the licensee has proposed increasing the RTD response time in the Technical Specifications to 8.0 seconds. The licensee has reanalyzed the affected FSAR Chapter 15 accident analyses in regard to the effect of the increased temperature response time of 8.0 seconds. For those accidents affected by increased response time, there are longer delays from the time when fluid conditions in the RCS require overtemperature delta-T (OTDT) or overpower delta-T (OPDT) reactor trips until a trip is actually generated. In the letter dated November 12, 1987, the licensee provided information on FSAR Chapter 15 non-loss-of-coolant accidents (non-LOCAs) that rely on the above-mentioned trips and that were evaluated with regard to the longer response time.

As noted in NUREG-0809, "Safety Evaluation Report - Review of Resistance Temperature Detector Time Response Characteristics," August 1981, extensive testing has revealed RTD response time degradation with aging. In view of this, surveillance tests are needed. The approved in situ method for measuring RTD response time is the loop current step response method. According to the letter dated December 23, 1987, this is the method used by the licensee. The RTD response time check is performed as part of the reactor trip system response time surveillance in Technical Specification 4.3.1.2. This test is required at least once every 18 months, at which time ascertaining the effects of the RTD response time is part of the OTDT and OPDT channel checks.

In response to a request for additional information, the licensee stated in the letter dated December 1, 1987 that RTDs at the South Texas plant are manufactured by the RdF Corporation and that the proposed 8.0-second total response time includes a processing delay of 1.5 seconds. The RTD response time typically accounts for 4.5 to 6.5 seconds. The accident analyses for South Texas have been performed assuming a total RTD response time of 8.0 seconds for OTDT and OPDT trips where applicable. On the basis of preliminary observations of RTD performance at lower primary temperatures (approximately 250°F), it is expected that there will be at least a 1-second margin in total response time in the worst case. In most cases, a margin of 2 or 3 seconds is expected.

RTD Uncertainty

The platinum resistance temperature sensors (RTDs) are believed to be very stable and to exhibit relatively small calibration drifts. However, according to several sources (Carr, 1972; Mangum, 1984; NUREG-0809), RTDs have been known to experience calibration shift. Therefore, when measuring the calorimetric heat balance at refueling, necessary steps (recalibration in a laboratory) should be taken to correct for any appreciable calibration drifts, or the RTD(s) should be declared inoperable and replaced. For small deviations found by the in situ cross-calibration method, the calibration of the resistance to voltage converters of the affected RTD(s) will be adjusted to account for the shift.

In the letter dated December 23, 1987, the licensee stated that the results of the tests that provide confirmatory information on the temperature accuracy of the RTDs will be provided to the NRC staff after the startup tests are completed.

Non-LOCAs Reanalyzed

The licensee examined FSAR Chapter 15 accidents to ascertain which should be reanalyzed because of the increase in RTD response time from 6.5 to 8.0 seconds.

Table 4.1 summarizes the non-LOCAs examined by the licensee that would not be affected by the increased RTD response time. Therefore, the existing FSAR analyses were unaffected for these accidents.

Table 4.2 summarizes the non-LOCAs examined by the licensee that might be affected by the increased RTD response time. These accidents were reanalyzed, and the results were found to be acceptable as noted in Table 4.2. The licensee provided information regarding the analyses including information on initial conditions and the resulting transient plots.

Three accidents - uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power, loss of load/turbine trip, and inadvertent opening of a pressurizer safety or relief valve - were affected by OTDT reactor trips as a result of longer delays from the time the fluid conditions in the RCS require a reactor trip until a trip is actually generated.

The steamline rupture accident analyses are discussed in FSAR Section 15.1.5. For the South Texas plant, the most limiting case is steamline rupture at zero power. In these analyses, initial hot shutdown conditions are assumed at time zero so the reactor is already in a tripped condition and RTD response time does not play a role in the zero-power steamline rupture. In the letter dated December 23, 1987, the licensee stated that the analyses performed again by Westinghouse for the steamline rupture at power, which include the effects of RTD time response, confirmed that the rupture at zero power is still the most limiting case for the departure from nucleate boiling ratio (DNBR).

Uncontrolled boron dilution at power is described in FSAR Section 15.4.6. In the letter dated November 12, 1987, the licensee stated that the sequence of events for the transient, when under manual control, is essentially identical to that for uncontrolled RCCA bank withdrawal at power. Boron dilution at power was analyzed on the basis of the results of the analysis of uncontrolled RCCA bank withdrawal at power, including the increased RTD response times.

In summary, the license has evaluated the effect of the increase in RTD response time from 6.5 to 8.0 seconds for the South Texas plant on the FSAR Chapter 15 non-LOCA analyses. For the events that were affected, the licensee demonstrated that the conclusions in the FSAR remain valid.

LOCA Evaluation

Review of the large-break-LOCA analysis (FSAR Section 15.6.5) for South Texas confirms that the RTD response times were not modeled in the analysis. This analysis was performed using the NRC-approved 1981 large-break evaluation model with BART. Therefore, the increase in RTD reponse times will not have any effect on the FSAR large-break-LOCA analysis for South Texas Units 1 and 2

Review of the small-break-LOCA analysis (FSAR Chapter 15.6.5) for South Texas confirms that the RTD response times were not modeled in the analysis. This

analysis was performed using the NRC-approved NOTRUMP evaluation model. Therefore, the increase in RTD response times will not have any effect on the FSAR small-break-LOCA analysis for South Texas Units 1 and 2.

Flow Measurement Uncertainty

In an NRC request for additional information, the licensee was asked to provide information regarding the uncertainties of the RTD temperature measurement. These could affect the flow measurement uncertainty analysis provided by the licensee by letter dated February 19, 1987, which shows a ±2.3 percent flow uncertainty value (not including 0.1 percent for feedwater venturi fouling). The licensee, however, has elected to use the Standard Technical Specification value of ±3.5 percent for flow measurement uncertainty. The staff believes that the ±3.5 percent uncertainty is sufficient to compensate for the effect of RTD temperature uncertainty. Therefore, further information regarding the effect of RTD temperature uncertainty on the flow measurement uncertainty analysis will not be needed unless the licensee intends to use the reduced flow measurement uncertainty value of ±2.3 percent.

Evaluation of Technical Specifications

As a result of the modifications associated with the increase in total response time of the RTDs from 6.5 to 8.0 seconds, the licensee proposed the following changes to the plant's Technical Specifications in the letter dated November 12, 1987. In Table 3.3-2, "Reactor Trip System Instrumentation Response Time" (page 3/4.3-9), the response time for Functional Unit 8, Overtemperature delta-T, and Functional Unit 9, Overpower delta-T, would be changed from 6.5 to 8.0 seconds. These changes are acceptable as explained above.

Conclusion

In SSER 2, the staff evaluated and found acceptable the elimination of the RTD bypass system at South Texas Unit 1 and the effect on the FSAR Chapter 15 non-LOCA analyses. For the events affected by the proposed increase in the channel response time, the licensee has demonstrated that the conclusions in the FSAR remain valid and the DNBR limit value is met. Thus, the proposed Technical Specification changes implementing the increased channel response time are acceptable.

4.4.8 Full-Flow-Filter Recovery

Inspection of the full-flow filters installed on the lower core support plate at South Texas Unit 1 revealed that degradation of 57 of the 192 filters had occurred during hot functional testing. The filters are used to help remove debris from the primary system. The degradation ranged from small tears and holes in the screen material to the complete loss of screens in four of the filters.

The licensee has inspected the equipment that was subjected to the filter debris during the hot functional tests and has evaluated the effects of unrecovered filter debris on the equipment in the primary system and certain auxiliary systems.

The results of the staff's review and evaluation of the licensee's activities to address the effects of filter debris on the condition of equipment exposed during the hot functional tests and the operability of equipment with unrecovered filter debris in the reactor coolant and auxiliary systems are provided below.

Areas of the primary coolant system and three auxiliary systems that had been exposed to the filter debris during hot functional tests were inspected and cleaned. The areas where filter debris was found and the amounts recovered are as follows:

- Reactor vessel bottom head (lower plenum) - Several small pieces were recovered.

- Thermowells - One wire piece was recovered.

- Steam Generator - Total amount recovered was 55.78 grams (1.97 ounces). Of this a small amount was in the divider plate drain holes and the remainder was in the tubes (minor particles also were found in the bowl area).

- Pressurizer outlet screen - 15 grams (0.53 ounce) were recovered.

- Residual heat removal heat exchanger - 3.2 grams (0.11 ounce) were recovered.

The inspection also showed that, except for some superficial scratches on the interior surface of the steam generator tubes in which the filter debris was found, no other evidence of physical damage was evident. The scratch marks in the steam generator tubes are considered to be insignificant.

On the basis of the amount of filter screen material recovered during the cleaning and inspection activities, the licensee estimates that approximately 77.3 percent of filter debris has been recovered and that the amount of unrecovered filter material is approximately 194 grams (6.85 ounces).

The licensee has performed an assessment of operational capability with the 194 grams of unrecovered filter debris in the primary coolant system. Two bounding forms of filter debris were assumed in the evaluation:

(1) a ball of wire 0.66 inch in diameter
(2) wire pieces 3/8 inch in length

These bounding geometries were based on the geometry of the filter debris recovered during the inspection activities. The results of the assessment for the reactor coolant system, auxiliary systems, and instrumentation are as follows.

Reactor Coolant System

The components within the reactor coolant system (RCS) that were evaluated to determine any possible adverse effects of the unrecovered filter debris are the

nuclear fuel, the reactor vessel and internals, the control rod drive mechanism, the steam generators, the pressurizer, the reactor coolant pumps, the primary system piping, and RCS materials. Although the presence of filter debris may result in fuel failures, Westinghouse states that the requirements in the Technical Specifications and normal surveillance activities can ensure that any degradation of performance of the RCS components will be detected and corrective action can be taken.

A review of the pump and valve inservice test plan indicates that alternate or redundant valves are subject to the same or comparable design and operational requirements as the primary valves. These alternate or redundant valves are available to perform the required function if the primary valve performance is degraded because of unrecovered debris.

Auxiliary Systems

Determination of the effect of unrecovered filter debris was limited to an evaluation of the functional capability of components within the chemical and volume control system, the residual heat removal system, the boron recycle system, the boron thermal regeneration system, the emergency core cooling system, and the reactor vessel head vent system. In all cases, it was determined that either the filter debris will not interfere with the operation of the components within these auxiliary systems or the safety function of these systems will be unaffected by the form and amount of the unrecovered core filter debris.

Instrumentation

The effect of the unrecovered filter debris on the capability of plant instrumentation to perform its intended function has been evaluated by the licensee.

The layout of instrument line connections to process lines (i.e., in vertical runs or above the midline in horizontal runs) and the static nature of the sensing lines make it unlikely that fouling of the sensing lines by filter debris will occur. No physical damage was observed during the plant inspection. Because of redundancy, plant instrumentation should continue to perform well even if there is a possibility of fouling as a result of unrecovered filter debris in the RCS.

The licensee reported that three French plants (Paluel 2, Flamanville 2, and Cattenom 1) that used full-flow filters of the same or similar design as those at South Texas Units 1 and 2 and experienced filter damage during hot functional testing have accumulated some operational experience without any problems after partial removal of the debris. Paluel 2 has completed nearly two fuel cycles; Flamanville 2 and Cattenom 1 have completed one cycle each. This operational experience supports the staff's conclusions regarding the operability of equipment with unrecovered filter debris in the reactor coolant and auxiliary systems at South Texas Unit 1.

Conclusion

The results of the licensee's plant inspection indicate no evidence of physical damage that would prevent the safe operation of the plant. The licensee's

evaluation demonstrates that the operability of the plant will not be affected even if unrecovered filter debris remains in the system. The staff, on the basis of its review of the licensee's submittal and responses to staff concerns, also concludes that the unrecovered filter debris does not constitute a threat to the safe operation of South Texas Unit 1.

Table 4.1 Non-loss-of-coolant-accident analyses not affected by increased RTD response time

FSAR section	Accident description	Effect on results
3.6	Blowdown reactor vessel and loop forces	No adverse effect on the LOCA hydraulic forcing functions
6.2	Containment subcompartment and long-term mass and energy release	No adverse effect on mass and energy releases
6.3.2.5	Hot leg switchover to prevent potential boron precipitation	No adverse effect on the post-LOCA hot leg switchover time
15.4.8	Rod ejection long-term mass	No adverse effect on mass releases
15.6.3	Steam generator tube rupture	No adverse effect on the consequences of the accident
15.6.5	Post-LOCA long-term core cooling	No adverse effect on the post-LOCA sump boron concentration

Note: There was no adverse effect on the emergency response guidelines (FSAR Section 13.5.2).

Table 4.2 Non-loss-of-coolant-accident analyses affected by increased RTD response time

FSAR section	Accident description	Effect on results
15.1.5	Steamline rupture at power	Analyses demonstrated that the departure from nucleate boiling ratio (DNBR) limit is met.
15.2.3	Loss of load/turbine trip	Analyses demonstrated that the DNBR limit is met and reactor coolant system pressure is maintained below 110 percent of the design value.
15.4.2	Uncontrolled rod cluster control assembly bank withdrawal at power	Analyses demonstrated that the DNBR limit is met.
15.4.6	Uncontrolled boron dilution at power	Analyses demonstrated that more than 15 minutes is available from the time of alarm until the total loss of plant shutdown margin.
15.6.1	Inadvertent opening of a pressurizer safety or relief valve	Analyses demonstrated that the DNBR limit is met.

6 ENGINEERING SAFETY FEATURES

6.2 Containment Systems

6.2.4 Containment Isolation System

By telephone on February 12, 1988 and letter dated February 18, 1988, the licensee informed the staff that the solenoid valves in the air supply lines to the containment personnel airlock seals had been overlooked in the identification of containment isolation valves. The licensee recognized that the valves in question should have been provided with the capability for either remote manual actuation or automatic actuation on receipt of a containment isolation signal.

The licensee took the following actions and requested the staff's review and approval:

(1) Initiated a design change to add the requisite circuitry. The licensee stated that the design would be complete on February 19, 1988 and installation would be complete before 5 percent power was exceeded.

(2) Changed operating procedures so that the solenoid valves will be maintained closed and deactivated when the airlock is operable.

(3) Included in the procedures a provision that when the valves are opened to recharge the air accumulators, a person will be stationed at the breaker that supplies power to the valves. This person is expected to close the valves if containment isolation is required.

(4) Instituted administrative controls for the personnel airlock to allow its use only for the passage of equipment into the containment.

The staff has reviewed the current design (Bechtel Energy Corporation Drawing 5C269F05060-1) and the change in design. Four ½-inch lines emanate from a pneumatic module outside the containment that provide compressed air to the airlock inflatable seals. Two of the lines provide compressed air to the inflatable seals of the airlock doors by means of accumulators located within the doors. Of these two lines, one passes completely through the containment wall and is connected to the inside airlock door from the containment side by means of a stainless steel flexible connection. The other line terminates in the airlock and is connected to the outside airlock door from the airlock by means of a stainless steel flexible connection. The two remaining ½-inch lines go to the stationary part of the pneumatic seals and are used for the seal leakage measurement system. There is a single ½-inch line for leakage measurement of the inner and outer seals.

Each of the four ½-inch lines has a solenoid valve installed in it. Valve FV-1025 controls the air supply to the outer seal, and valve FV-1026 controls the air supply to the inner seal. Valves FV-1027 and FV-1028 are installed in the leak rate lines for the outer and inner seals, respectively.

On the basis of information provided by the licensee, the staff has concluded that the four ½-inch lines to the airlock pneumatic seals must conform with General Design Criterion (GDC) 57 of 10 CFR 50, Appendix A. The solenoid valves installed are acceptable as isolation valves, but do not receive a signal to close on containment isolation. To conform to GDC 57, the licensee proposed an interim measure to close these solenoid valves with the power source locked out except when the seals require replenishment of the air supply. At such times, the licensee proposed to station an operator at the valve control to manually close the valve should containment isolation occur. The operator would remain at the valve controls until the valve was closed and the power to the valve was again locked out. For the long run the licensee has committed to modify the solenoid valve circuitry to allow automatic closure on containment isolation. The modifications will be complete before 5 percent power is exceeded.

Locked-closed valves are acceptable as a means of complying with GDC 57. Locking open the power supply to a closed solenoid valve has the same effect as locking closed a manually operated valve. Therefore, the staff concluded that a closed solenoid valve with a locked-open power supply is the equivalent of a locked-closed valve and is in conformance with GDC 57.

For this interim application, the staff considers a manually controlled valve with an operator stationed at the controls the equivalent of a valve that is operated remote manually.

The amount of radioactivity that can potentially leak through the ½-inch line is quite low. Each line includes an ASME Code, Section III, Class 2 check valve. The radioactive source would have to overcome the instrument line air pressure. The final design of automatic isolation will be implemented before the plant exceeds 5 percent of rated power. In the interim the valves would be locked closed except for short periods for recharging the accumulators; during those periods they would be under administrative control.

Conclusions

The actions taken by the licensee, the design change, and the schedule for implementation of its commitments are acceptable to the staff in terms of meeting the regulatory requirements regarding containment integrity. The actions taken by the licensee are sufficient to ensure the operability of the personnel airlock as well as the containment isolation system. Since the licensee's letter requests temporary waiver of Technical Specification 3.0.4 for the air supply lines to the containment personnel airlock seals, the staff grants such waiver to permit change of modes and to continue the testing program, although it may not be necessary to invoke Specification 3.0.4 when the valves in question are considered operable. The staff will ensure implementation of the licensee's commitment before 5 percent of rated power is exceeded.

7 INSTRUMENTATION AND CONTROLS

7.8 Use of Jumpers and Lifted Leads

The staff has reviewed the licensee's submittal dated June 23, 1987, with respect to the use of jumpers and the lifting of leads during the performance of routine maintenance and surveillance testing procedures. As stated in the letter, the licensee recognizes the problems associated with the use of jumpers and, as a result, has committed to follow Plant Procedure Manual OPMOS-ZE-0400.

The procedures of this manual specifically address the practice of using jumpers and lifted leads during the performance of maintenance and surveillance testing of safety-related components for the South Texas plant. When the use of jumpers or the lifting of leads is required, testing will be conducted in accordance with the recommendations in Office of Inspection and Enforcement (IE) Information Notice 84-37, "Use of Lifted Leads and Jumpers During Maintenance or Surveillance Testing." This plant manual will be used whenever the plant procedures necessitate using jumpers or lifting leads in order to complete required maintenance and surveillance testing of safety-related components. Jumpers or lifted leads will only be used in safety-related systems when no other practical means is available to accomplish the recessary maintenance and surveillance testing functions.

The staff concludes that the above manual includes the essential key elements of IE Information Notice 84-37 to preclude the degrading of system functions as a result of the inappropriate practice of lifting leads or using jumpers and to ensure that the safety-related equipment is restored to normal conditions after testing.

9 AUXILIARY SYSTEMS

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

The low-power license issued for South Texas Unit 1 on August 21, 1987 incorporated a license condition that the provisions of the approved fire protection program be implemented. The description of the program is contained in the Fire Hazards Analysis Report through Amendment 7 as well as in letters submitted by the licensee, the most recent of which are dated June 11, 25, and 26, 1987. The program description identified certain deviations from the National Fire Protection Association codes, and the staff has documented approval of most of the deviations in the SER and the four subsequent supplements. The deviations that were not specifically addressed were considered of minor significance. Hence, all deviations identified in the above submittals may now be considered as approved and future changes are to be governed by the license condition, which states: "HL&P may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire."

13 CONDUCT OF OPERATIONS

13.3 Emergency Planning

13.3.1 Introduction

The licensee filed Revision 8 of the South Texas Project Electric Generating Station Emergency Plan with the NRC on February 19, 1988. Previously, the staff had reviewed and commented on earlier revisions of the emergency plan and provided a finding of adequacy in SSER 3 for onsite emergency planning and preparedness for the South Texas Project based on Revision 3 of the plan.

The staff has reviewed Revisions 4, 5, 6, 7, and 8 against the same requirements and guidance criteria identified in SSER 3; namely, 10 CFR 50.47(b), Appendix E to 10 CFR 50, and NUREG-0654/FEMA-REP-1, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," dated November 1980. An updated staff evaluation of the onsite emergency plan is presented in Sections 13.3.2 and 13.3.3 of this supplement.

The Federal Emergency Management Agency (FEMA) has reviewed the State and local plans including an evaluation of the full-participation exercise conducted at the South Texas Project. The FEMA findings are presented in Section 13.3.4 of this supplement. The staff's overall finding of adequacy for onsite and offsite emergency preparedness is provided in Section 13.3.5.

13.3.2 Evaluation of the Emergency Plan

The licensee underwent a management reorganization at the South Texas Project site since the staff's evaluation of Revision 3 of the emergency plan. Some positions and personnel affected by the reorganization are assigned to key positions in the station emergency response organization. The licensee has submitted Revisions 4, 5, 6, 7, and 8 to the emergency plan, which incorporate the changes to the management organization.

The staff has reviewed the changes made to the emergency plan by the licensee which were necessitated by the management reorganization. The staff finds that the emergency response organization described in Revision 7 of the emergency plan is consistent with the current management organization. The staff concludes that adequate staffing is provided to respond to an emergency and that the emergency plan continues to provide an adequate planning basis for onsite emergency preparedness.

13.3.3 Notification Methods and Procedures

In SSER 3, the staff noted that the tone alert radios, which are part of the prompt notification system for the South Texas Project, were to be distributed. The licensee has confirmed that the distribution of the tone alert radios to the residents and establishments within the plume exposure pathway emergency planning zone has essentially been completed.

13.3.4 FEMA Offsite Emergency Preparedness Evaluation

In accordance with FEMA's rule, 44 CFR 350, the State of Texas submitted its State and associated local plans for radiological emergencies related to the South Texas Project to FEMA for review and approval. FEMA reviewed the State and local plans including an evaluation of the full-participation exercise conducted at the South Texas Project on April 8, 1987. FEMA's review of the emergency plans included a review of the medical services capabilities for the State of Texas and Matagorda County pursuant to FEMA Guidance Memorandum MS-1, "Medical Services."

In a letter to the NRC dated June 5, 1987, FEMA provided its determination that the State and local emergency response plans for the South Texas Project are adequate to protect the health and safety of the public in that there is reasonable assurance that the appropriate protective measures can be taken off site in the event of a radiological emergency. In a letter to the NRC dated September 30, 1987, FEMA reported that the full-participation exercise conducted at the South Texas Project on April 8, 1987 demonstrated satisfactory capability to protect the health and safety of the public.

13.3.5 Conclusions

On the basis of its review of the South Texas Project Electric Generating Station Emergency Plan to determine if it conforms to the criteria in NUREG-0654/FEMA-REP-1, the staff concludes that the emergency plan provides an adequate planning basis for an acceptable state of onsite emergency preparedness and meets 10 CFR 50 and Appendix E thereto. FEMA has provided its findings and determinations on the adequacy of offsite emergency planning and preparedness. On the basis of its review of the FEMA findings on the adequacy of State and local plans and preparedness and its assessment of the adequacy of the licensee's onsite emergency plans and preparedness, the staff concludes that the overall state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at the South Texas Project.

13.5 Plant Procedures

13.5.2 Operating and Maintenance Procedures

13.5.2.4 NUREG-0737 Item III.D.1.1, Primary Coolant Outside Containment

In SSER 2, the staff documented the adequacy of the licensee's compliance with NUREG-0737 Item III.D.1.1, with a condition that the licensee apply the leakage reduction program to the chemical and volume control system (CVCS). On May 1, 1987, the licensee made a commitment to include the CVCS in the ASME Code Section XI program. This commitment removes the condition placed on the resolution of this item.

13.6 Industrial Security

13.6.1 Introduction

The licensee had filed with the NRC the following security plans, which have since been amended:

(1) South Texas Project Electrical Generating Station Physical Security Plan

(2) South Texas Project Electrical Generating Station Safeguards Contingency Plan.

(3) South Texas Project Electrical Generating Station Security Personnel Qualification and Training Plan.

This supplement summarizes the commitments in the licensee's letter of November 17, 1987 that relate to the above plans and that were requested by the NRC staff during a meeting on October 30, 1987. In South Texas Project License NPF-71, the NRC imposed a condition on initial criticality that required that the licensee take appropriate action to demonstrate satisfactory long-term performance of the intrusion detection system (IDS).

The Unit 1 IDS has undergone several modifications to decrease the false alarm rates (FARs) and nuisance alarm rates (NARs), particularly during inclement weather. The system is effective in regard to intrusion detection, and the FARs and NARs have decreased considerably (specific protected data have been provided by the licensee) since the low-power license was issued. The security force personnel have developed their skills in the operation of the IDS so that they are able to assess and respond to the alarms now being experienced. System/zone unavailability and consequent posting of officers is substantially less frequent than in early 1987.

The licensee is planning additional actions to further decrease the FARs and NARs of the IDS. These actions, which include the following, will be completed in the first quarter of 1988:

- Rework drainage across the protected area boundary to minimize the effect of standing and moving water on the alarm system.
- Rework the IDS that crosses over the roof of the east gatehouse.
- Evaluate other potential improvements such as improved grounding techniques, newer mounting hardware, different wire configurations, and variations in sensitivity.

Other planned improvements include the following:

- Closed-Circuit Television (CCTV) System

  In a letter dated July 24, 1987, the licensee committed to implement a number of modifications to improve the assessment capability of the CCTV system. The modifications involve realignment of fences and/or relocation of cameras to provide improved coverage of the protected area boundary and isolation zone.

  The licensee plans to complete the modifications within 6 months after the full-power license is issued. Design and implementation details will be made available for NRC staff review as they are developed. The actual configurations will be designed to best ensure assessment capability and

may differ in some respects from the description provided in the above-referenced letter.

In addition to the fence/camera realignment, the licensee plans to relocate a number of IDS controller boxes to provide a better barrier configuration and to enhance maintenance.

- Unit 1 Southwest Perimeter

  The southwest corner of the Unit 1 perimeter has been routed around the startup building (located outside the protected area) so as to create an undesirable boundary configuration.

  The licensee plans to remove the building and straighten the fence in order to eliminate the configuration by mid-February of 1988.

- Essential Cooling Water Intake Structure (ECWIS) Intrusion Detection System

  The licensee plans to improve the IDS for the ECWIS to reduce the surveillance burden currently imposed on the security officers. The licensee plans to determine the IDS that will be used and implement modifications as early as practicable in the first quarter of 1988.

- Unit 1 North Gatehouse

  The licensee plans to remodel the Unit 1 north gatehouse to provide improved traffic flow and badging facilities and capabilities. The improvements involve relocating the entry and exit turnstiles and enlarging and hardening the badging area. Completion is scheduled for February 1988.

- Unit 1 East Gatehouse

  In order to expedite the entry and exit of personnel through the east gatehouse, the licensee will remodel the facility by rearranging detection equipment and adding a new badge-check window. This remodeling is scheduled for completion in the second quarter of 1988.

- Alarm Stations

  The licensee has determined that improvements are necessary in the central and secondary alarm stations in order to support the bringing of Unit 2 into the security system. The improvements involve the installation of new consoles, improved integration of communications, and improved response of the CCTV monitors. These improvements will be completed to support Unit 2 lockdown, which is scheduled for November 1, 1988.

- Unit 2 Intrusion Detection System

  The licensee has decided to install a new type of IDS for Unit 2. This IDS is scheduled to be installed, tested, and operational by lockdown of Unit 2.

- Unit 2 West Gatehouse and Security Facilities

  The licensee has identified the need for a west gate to provide access to Unit 2. The gatehouse design will be similar to that of the improved Unit 1 north gatehouse.

  To support the Unit 2 security officer force, additional facilities will be constructed for lockers, armory, offices, assembly area, etc.

- Unit 2 Vehicle Protection Barrier

  As in Unit 1, the licensee will provide Unit 2 with barriers that will ensure protection from vehicles breaching the protected area fence. The protection barriers will be built so as to take advantage of natural features such as ditches and utilize design features such as concrete barriers and cable where appropriate. The barriers will be in place by lockdown of Unit 2.

- Roof Lighting

  The licensee will provide both units with roof lighting adequate to meet the 0.2-foot-candle regulatory requirement. Temporary lighting is already in place at Unit 1. It will be upgraded to permanent lighting by lockdown of Unit 2. Unit 2 roof lighting will be installed and operational by lockdown.

Conclusions

On the basis of its review of the above-referenced document and meeting, the staff concludes that the protection provided by the licensee against radiological sabotage at South Texas satisfies License Condition F(1) and the commitment in the licensee's letter of July 30, 1987 regarding the completion of a study of the Unit 1 intrusion detection system 90 days after the low-power license was issued.

16 TECHNICAL SPECIFICATIONS

16.1 Limiting Conditions for Operation and Surveillance Requirements

The licensee proposed changes to Technical Specifications 3.0.4, 4.0.3, and 4.0.4 in a letter dated November 12, 1987 in accordance with NRC Generic Letter 87-09. The generic letter informed licensees that they are encouraged to propose the type of changes requested by the licensee in the November 12, 1987 letter. In response to a staff request, the licensee provided, in a letter dated December 11, 1987, marked-up copies of the pages of the Technical Specifications with the actual changes. The staff has reviewed the proposed changes submitted in the November 12 and December 11, 1987 letters and finds that they are consistent with the intent of Generic Letter 87-09. Implementation of the proposed changes will remove unnecessary restrictions on the operation of the plant, improve the consistency within the Technical Specifications, and eliminate potential sources of conflict between Technical Specifications as indicated in Generic Letter 87-09. Hence, the staff approves the changes proposed in the above-mentioned letters.

16.2 Snubbers

By letter dated April 20, 1987, the licensee requested relief from the inspection and test schedule requirements of the 1983 Edition through Summer 1983 Addenda of Section XI of the ASME Code related to mechanical snubbers at South Texas Units 1 and 2. As an alternative to the inspection schedule required by Section XI, the licensee has proposed to use the more frequent inspection schedule required by Technical Specification 3/4.7.9.

The staff has reviewed the licensee's request, the inspection requirements of Section XI and Technical Specification 3/4.7.9, and the licensee's basis for requesting to use the inspection and test schedule delineated in Technical Specification 3/4.7.9. The staff agrees with the licensee that the Technical Specification requirements meet or exceed the requirements of ASME Code Section XI and are therefore acceptable. Tests performed under Technical Specification requirements that are also required by Section XI need not be duplicated but should be documented to show that they were performed in accordance with those requirements.

16.3 Administrative Controls

By letters dated November 12, 1987, January 28, 1988, and March 10, 1988, the licensee requested changes to the Administrative Controls section of the Technical Specifications for South Texas Unit 1.

Taken together, the licensee requests the following amendments:

(1) Revise Technical Specification 6.5.1.8 ("Records") to require that the minutes of Plant Operations Review Committee (PORC) meetings be provided to the Vice President-Nuclear Plant Operations rather than to the Group Vice President-Nuclear.

(2) Revise Figures 6.2-1 and 6.2-2 showing the offsite and onsite organizations, respectively. The revisions incorporate new positions under the Vice President, Engineering and Construction, and under the Plant Manager.

(3) Revise Technical Specifications 6.5.1.2 and 6.5.1.5 regarding PORC composition and quorum so as to be consistent with the organizational changes, as well as respond to the staff's comments on the January 28, 1988 request.

(4) Revise Technical Specification 6.5.2.2 regarding the composition of the Nuclear Safety Review Board to be consistent with the organizational changes and to permit the Group Vice President-Nuclear to appoint additional members.

The staff finds the first change unacceptable because it believes that PORC meeting minutes should be provided to the person i the management position with overall responsibility for South Texas Unit 1. The staff finds the other changes acceptable and hereby approves them.

16.4 Safety Injection Flow Rates

By letter dated July 16, 1987, the licensee certified that the final draft Technical Specifications of the South Texas Project issued on May 18, 1987, as revised by the draft page changes issued on July 7, 1987, were consistent with its FSAR and the SER and its supplements issued by the staff. The revised draft Technical Specifications of July 7, 1987 changed the minimum and maximum high head safety injection (HHSI) flow rates of 1,440 and 1,600 gallons per minute (gpm) to 1,470 and 1,620 gpm, respectively. In addition, the minimum low head safety injection flow rate was changed from 2,570 gpm to 2,550 gpm. With respect to these changes in the safety injection (SI) flow rates, the licensee also provided an impact evaluation to justify the changes. The staff's evaluation follows.

The previous analyses of all the transients and accidents that may be affected by the revised SI flow rates should be re-evaluated. The licensee has evaluated both LOCA and non-LOCA transients and accidents.

For the large-break LOCA, the previous sensitivity analysis showed that the use of a maximum SI flow rate would result in a more limiting calculated peak cladding temperature (PCT). Therefore, a reanalysis was made to determine the effect of the revised maximum HHSI flow rate on PCT. The result showed an increase of 28F° in PCT for the limiting double-ended cold-leg guillotine break of 0.6. The licensee also considered the effect of changing the uncertainty of the average coolant temperature from 4F° to 5F°, which results in an increase of a 5F° penalty in PCT. The overall results showed a PCT of 2127°F, a 73F° margin to the acceptance criterion of 2200°F, as shown in the revised FSAR.

For the small-break LOCA, the previous analysis showed a PCT of 1366.4°F for the limiting 4-inch cold leg break and the minimum SI flow rate. The sensitivity study performed by the licensee showed an increase of 34F° in PCT as a result of the revised minimum low head SI flow rates. Therefore, there is still a large margin from the acceptance criterion of 2200°F. This result is also shown in the revised FSAR submitted in a letter dated July 28, 1987.

With regard to the steam generator tube rupture (SGTR) accident, the licensee indicated that the current SGTR analysis is bounding for the maximum HHSI flow rate of 1,620 gpm. In the July 28, 1987 letter, the licensee further committed to provide, before restart following the first refueling outage, an SGTR reanalysis based on the methods approved by the Westinghouse Owner's Group.

Other criteria such as the post-LOCA long-term cooling requirement and blowdown reactor vessel force were examined by the licensee; the effects were none or negligible. The licensee also evaluated each of the non-LOCA transients affected by the revised SI flow rates and found that the effect on the results was negligible with respect to the acceptance criteria for each transient.

The staff has reviewed the information on the revised SI flow rates in the South Texas Technical Specifications. Since those transients affected by the revised SI flow rates still satisfy applicable regulatory requirements, the staff concludes that the revised Technical Specifications for the SI flow rates are acceptable.

16.5 Turbine Overspeed Protection

In a letter dated February 24, 1987, the licensee initially requested deletion of Technical Specification 4.3.a.2 pertaining to turbine valves (turbine overspeed). The basis for the licensee's request was that the staff had approved a similar proposal for Farley Unit 2 and the South Texas turbine overspeed protection design was similar to that of Farley. Staff approval of the Farley request was based on a review of the turbine overspeed reliability assurance program (TORAP), the results of which were contained in Westinghouse Electric Corporation reports WCAP-10161 and -10162, where the reliability of the turbine overspeed protection system and the potential for turbine missile generation for Farley Unit 2 was evaluated. This information included data on turbine valve reliability over several years and was specific to Farley Unit 2.

The staff concluded that the above justification was insufficient for totally deleting turbine valve testing requirements from the Technical Specifications because no plant-specific data on the valves were available for South Texas because of its short operating history. The licensee indicated it had contracted with Westinghouse Electric Corporation to perform warranty inspections on the turbine and generator systems during the initial three scheduled refueling outages and that within 3 years of the completion of the contractual period, it would implement a turbine maintenance/inspection program that incorporates the Westinghouse recommendations. The staff notified the licensee that until a complete maintenance/inspection program and a comprehensive plant-specific TORAP were provided, deletion of the turbine overspeed protection Technical Specification could not be approved.

By letter dated September 23, 1987, the licensee submitted a revised proposal for a change to Technical Specifications 4.3.4.2.a and 4.3.4.2.b. This proposed change would reduce the frequency for main turbine valve testing from weekly to monthly. The valves affected are the high pressure turbine stop and governor valves and the low pressure turbine reheat stop and intercept valves. In addition, the proposed change would revise the applicability of the Technical Specifications to modes 1 and 2 only when the main turbine is operating. When

the turbine is shut down (not running), the steam admission valves are shut and turbine missile generation is not possible. The proposed relaxation from weekly to monthly testing of the turbine valves is consistent with the turbine manufacturer's (Westinghouse) recommendation for ensuring adequate valve operability. In addition, the testing of valves in modes other than modes 1 and 2 is inappropriate because their operability is important only when the turbine is at power, and testing the valves when the turbine is shut down imposes an unnecessary thermal shock on the turbine. The staff, therefore, finds the licensee's proposed Technical Specification changes in accordance with the guidelines for ensuring against postulated turbine missiles as a result of turbine overspeed.

On the basis of the above, the staff concludes that extending the turbine valve testing intervals from weekly to monthly and limiting the surveillance testing to modes 1 and 2 is acceptable because these changes are in accordance with staff criteria for ensuring against postulated turbine missiles as a result of failures in the turbine overspeed protection system.

16.6 Diesel Generator Rotational Speed

By letter dated September 23, 1987, the licensee requested that Surveillance Requirement 4.8.1.1.2.a(2) be changed from the following:

> Ver..,ing the diesel starts from ambient condition and accelerates to at least 600 rpm in less than or equal to 10 seconds.

to the following:

> Verifying the diesel starts from ambient condition and accelerates to 600 rpm (nominal) in less than or equal to 10 seconds.

The staff reviewed the request and approved it on the basis that the acceptable performance of the diesel generator is determined by the output voltage and frequency that have been specified in the Technical Specifications as 4,160 ± 416 volts and 60 ± 1.2 hertz, respectively. Because of the fixed relationship between the output frequency and the generator rotational speed, the frequency range of 60 ± 1.2 hertz translates to a speed range of 588 revolutions per minute (rpm) to 612 rpm. This range is acceptable as a criterion for satisfactory performance of the diesel generators.

16.7 Containment Tendons Surveillance Requirements

On December 14, 1987, the licensee proposed a change in Technical Specification 4.6.1.6.1.b.(1) so as to bring the acceptance criterion in line with the Standard Technical Specifications, NUREG-0452. The integrity of the tendons is ensured by the inspection program, which would detect an unacceptable level of degradation in the tendon wires and strands. Additionally, the licensee proposed a change in the Bases section of Technical Specification 3/4.6.1.6 to bring about consistency between the version of Regulatory Guide 1.35 referenced in the Technical Specifications and the commitments made in FSAR Table 3.12.1. The staff finds the proposed changes acceptable.

16.8 Clarification of Limiting Condition for Operation for High Head Safety Injection Pumps in Mode 4

By letter dated February 11, 1988, the licensee proposed a change in Technical Specification 3.5.3.1 to clarify the limiting condition for operation for high head safety injection (HHSI) pumps in Mode 4.

Technical Specification 3.5.3.1 makes reference to two operable pumps. The requested change is intended to clarify this requirement. The basis for Technical Specification 3.5.3.1 describes the emergency core cooling system requirements as being balanced between the limitations imposed by the low temperature overpressure protection and the requirements necessary to mitigate the consequences of a loss-of-coolant accident when the reactor coolant system temperature is below 350°F. Only one low head safety injection (LHSI) pump is required to mitigate the effects of a large-break LOCA in this mode. Two pumps are provided to accommodate the possibility that the break occurs in a loop containing one of the LHSI pumps.

The staff has reviewed the licensee's request to clarify the limiting condition for operation, the basis for clarification, and the licensee's justification for the proposed change. The staff finds the proposed change acceptable.

APPENDIX A

CONTINUATION OF NRC STAFF RADIOLOGICAL REVIEW
OF THE SOUTH TEXAS PROJECT

June 25, 1987	Letter from applicant concerning the fire hazards analysis.
June 26, 1987	Letter from applicant concerning the fire hazards analysis.
June 29, 1987	Letter from applicant concerning revisions to Section 8.3.1.1 of the Final Safety Analysis Report (FSAR) - description (ac power system).
June 30, 1987	Letter from applicant concerning revised final draft Technical Specifications.
June 30, 1987	Letter from applicant concerning advisor to Plant Operations Manager.
June 30, 1987	Letter from applicant concerning FSAR Amendment 58 - radioactive equipment and floor drain sump system preoperational tests.
June 30, 1987	Letter from applicant concerning preservice inspection summary report for Class 1, 2, and 3 component supports.
June 30, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-23 and 50-499/87-23 covering period of April 11-May 4, 1987.
July 1, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-29 and 50-499/87-29 covering period of May 18-22, 1987.
July 1, 1987	Letter to applicant forwarding Examination Report 50-498/87-02 covering May 12, 1987.
July 1, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-37 and 50-499/87-37 covering period of April 13-June 11, 1987.
July 1, 1987	Letter from applicant forwarding followup response to support Open Item 87-08-34 from Inspection Reports 50-498/87-08 and 50-499/87-08.

July 1, 1987	Letter from applicant submitting status of emergency preparedness-related open items, including Open Items 86-35-16 and 86-35-32.
July 2, 1987	Letter to applicant informing parties that Chairman Zech plans to tour South Texas Project on July 27, 1987.
July 2, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-35 and 50-499/87-35 covering period of June 8-12, 1987.
July 3, 1987	Letter from applicant forwarding revisions to SAFETEAM program instructions.
July 4, 1987	Letter to NRC from R. J. Henschen expressing concern over construction mismanagement and safety violations at South Texas. Supports Government Accountability Project (GAP) petition for independent investigative team to inspect plant before it is licensed to load fuel or begin operation.
July 6, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-13 and 50-499/87-13 covering period of April 13-17, 1987.
July 6, 1987	Letter from applicant concerning completion of equipment qualification.
July 6, 1987	Letter from applicant responding to violations noted in Inspection Report 50-498/87-21.
July 7, 1987	Letter to applicant concerning certification of revised final draft Technical Specifications for South Texas Unit 1.
July 7, 1987	Letter from applicant concerning quality assurance program for fire protection systems.
July 8, 1987	Letter from H. B. Gonzalez urging Commission consideration of petitions seeking delay of plant startup operation; specifically, Citizens Concerned About Safety motion and GAP petition to reopen record and to investigate allegations, respectively.
July 8, 1987	Letter from applicant concerning elimination of arbitrary intermediate breaks.
July 8, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-33 and 50-499/87-33 covering period of June 8-12, 1987.
July 9, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-42 and 50-499/87-42 covering period of June 22-24, 1987.

July 10, 1987	Memorandum from P. Kadambi (NRC) to T. Murley concerning hold points during power ascension, South Texas Unit 1.
July 10, 1987	Letter from applicant concerning update of statement of completion and request for low-power operating license.
July 10, 1987	Letter from applicant concerning the security plan.
July 13, 1987	Letter from NRC Acting Chairman F. Bernthal to G. Barrientos concerning two pending motions before the NRC regarding South Texas. A decision will be rendered on both motions in the near future.
July 14, 1987	Letter from applicant concerning request for additional information on preoperational test status.
July 14, 1987	Letter to applicant responding to its letter of June 12, 1987 concerning corrective actions taken for inspection conducted on April 6-10, 1987.
July 15, 1987	Letter to B. P. Garde responding to May 29, 1987 petition under 10 CFR 2.206 for establishment of investigative unit independent of NRC Region IV and Executive Director for Operations to review allegations on South Texas Project.
July 15, 1987	Letter from applicant concerning observations of the NRC operational readiness review team.
July 15, 1987	Memorandum and Order denying B. P. Garde motion to quash subpoena and request for oral argument.
July 15, 1987	Letter from applicant concerning NRC June 15, 1987 Notice of Violation 8719-01.
July 16, 1987	Letter from applicant concerning resolution of concerns relative to Bechtel's ME101 stress analysis program.
July 16, 1987	Letter from applicant concerning certification of revised final draft Technical Specifications.
July 17, 1987	Letter from applicant concerning Office of Inspection and Enforcement (IE) Bulletin 86-02 regarding statice "O" ring differential pressure switches.
July 21, 1987	Letter from applicant concerning NRC June 22, 1987 letter regarding violations noted in Inspection Reports 50-498/87-21 and 50-499/87-21.
July 22, 1987	Letter from applicant concerning NRC June 22, 1987 letter regarding violations noted in Inspection Reports 50-498/87-27 and 50-499/87-27.

July 23, 1987	Letter from Paul-Munroe Energy Products concerning final report in regard to potential 10 CFR 21 report regarding pressure switches.
July 23, 1987	Letter from applicant concerning response to Freedom of Information Act request.
July 24, 1987	Letter from applicant concerning security plan.
July 24, 1987	Letter from applicant concerning NRC Operator License Examination Report OL-87-02.
July 24, 1987	Memorandum and Order - Citizens Concerned About Nuclear Power, Inc., May 29, 1987 motion to reopen record of facility licensing hearings and request for stay of fuel loading denied.
July 24, 1987	Letter from applicant concerning quality assurance program for the design and construction phase of the South Texas Project.
July 24, 1987	Letter to applicant acknowledging receipt of June 25, 1987 letter informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-08 and 50-499/87-08.
July 27, 1987	Letter to applicant acknowledging receipt of June 22 and July 1, 1987 letters informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-08 and 50-499/87-08.
July 27, 1987	Letter from applicant concerning NRC June 25, 1987 letter regarding deviations noted in Inspection Report 50-498/87-26.
July 28, 1987	Letter from applicant concerning revised safety injection flow.
July 29, 1987	Letter from applicant concerning exemption request for final draft Technical Specification Surveillance Requirement 4.3.4.2.d.
July 30, 1987	Letter from applicant concerning the security plan.
July 31, 1987	Letter from applicant concerning annotated revision to FSAR Section 14.2.12.3 in regard to loss-of-offsite-power (LOOP) test.
July 31, 1987	Letter from applicant concerning exemption request for final draft Technical Specification Surveillance Requirement 4.3.4.2.d.
July 31, 1987	Letter from applicant concerning Technical Specification 3/4.5.2 - emergency core cooling system subsystem.

August 3, 1987	Letter from applicant concerning final report on essential cooling water pump damage.
August 3, 1987	Letter from applicant concerning rod drop testing.
August 4, 1987	Letter from applicant concerning final report on engineered safety features actuation signal reset (IE Bulletin 80-06).
August 4, 1987	Letter to applicant acknowledging receipt of July 22, 1987 letter informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-27 and 50-499/87-27.
August 6, 1987	Letter to applicant concerning issuance of SSER 4.
August 7, 1987	Letter from applicant concerning the security plan.
August 10, 1987	Letter from applicant concerning contingency response.
August 12, 1987	Letter from applicant concerning moveable incore detector test.
August 12, 1987	Letter from applicant concerning resolution of concerns relative to Bechtel's ME101 stress analysis program.
August 12, 1987	Letter from applicant concerning final report on FGP series agastat relays.
August 14, 1987	Letter to applicant forwarding Inspection Reports 50-498/87-44 and 50-499/87-44 covering period of June 22-July 10, 1987.
August 18, 1987	Letter from applicant concerning security training program.
August 18, 1987	Letter from applicant concerning observations of the NRC operational readiness review team.
August 19, 1987	Letter from applicant concerning Open Item 498/87-31-01.
August 21, 1987	Letter to licensee concerning issuance of Facility Operating License NPF-71 for South Texas Unit 1 for 5 percent power.
August 21, 1987	Letter from licensee concerning final report on engineered safety features load sequencing.
August 24, 1987	Letter to licensee concerning Allegation 4-87-A-005 regarding dismissal of J. R. Bryant for raising safety concerns while performing quality control inspection duties.
August 26, 1987	Letter to licensee concerning approval of Revision 19 to quality assurance program for the design and construction phase of the South Texas Project.

August 26, 1987	Letter from licensee concerning first interim report on standby diesel generator fuel injection nozzles.
August 26, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-46 and 50-499/87-46 covering period of August 3-7, 1987.
August 27, 1987	Letter to L. A. Sinkin concerning receipt of petition for Director's decision under 10 CFR 2.206.
August 28, 1987	Letter from licensee concerning security event report regarding security officer attentiveness on duty.
August 28, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-27 and 50-499/87-27 covering period of August 20-June 26, 1987.
August 31, 1987	Letter from licensee concerning first interim report on cooling of the standby diesel generator high voltage cubicle panels.
August 31, 1987	Letter from licensee concerning SER Confirmatory Item 1 - meterological measurements program, additional information.
September 1, 1987	Letter to licensee accepting June 23, 1987 offer to review with utility adequacy of plant hardware and operating staff performance before ascension to 75 percent plateau.
September 2, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-32 and 50-499/87-32 covering period of May 11-15, 1987.
September 2, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-38 and 50-499/87-38 covering period of June 16-19, 1987.
September 3, 1987	Letter to licensee concerning regulatory effectiveness review for fiscal year 1988.
September 4, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-47 and 50-499/87-47 covering period of June 27-July 31, 1987.
September 4, 1987	Letter from licensee concerning security event report regarding badge/key card set outside protected area.
September 5, 1987	Letter from licensee concerning security event report regarding electronic security systems failure.
September 9, 1987	Letter from licensee concerning security event report regarding badge/key card set issued incorrectly to an employee.

September 10, 1987	Letter from licensee concerning security event report regarding inadvertent activation of emergency evacuation feature of electronic security system.
September 10, 1987	Letter to licensee acknowledging receipt of letter dated July 21, 1987 informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-21 and 50-499/87-21.
September 10, 1987	Letter from licensee concerning fifth interim report on Veritrak transmitters.
September 11, 1987	Letter to licensee acknowledging receipt of letter dated August 19, 1987 informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-31 and 50-499/87-31.
September 14, 1987	Letter to licensee concerning confirmation of meeting in Region IV office on September 18, 1987 regarding the security program at South Texas Project.
September 14, 1987	Letter from licensee concerning preliminary response to NRC Bulletin 87-001 - thinning of pipe walls in nuclear power plants.
September 14, 1987	Letter to licensee acknowledging receipt of letter dated July 27, 1987 informing the NRC of steps taken to correct deviations noted in Inspection Report 50-498/87-26.
September 16, 1987	Letter from licensee concerning Amendment 1 to Indemnity Agreement No. B-108.
September 16, 1987	Letter to licensee forwarding criteria that will be used in determining operability of facility intrusion detection system.
September 17, 1987	Letter from licensee concerning security event report regarding vital area door found improperly secured.
September 17, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-40 and 50-499/87-40 covering period of May 11-July 3, 1987.
September 17, 1987	Letter from licensee responding to NRC letter dated August 18, 1987 concerning violations noted in Inspection Report 50-498/87-39.
September 17, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-41 and 50-499/87-41 covering period of June 15-July 2, 1987.
September 18, 1987	Letter to licensee documenting the meeting and tour of the South Texas Project, Unit 1, on July 28, 1987.

September 20, 1987	Letter from licensee concerning security event report regarding the breaching of a security barrier at a pipe penetration.
September 21, 1987	Letter from licensee concerning additional information on the resolution of concerns relative to Bechtel's ME101 stress analysis program - submittal of revised information supporting the accumulatory line and attachments leak before break.
September 21, 1987	Letter from licensee forwarding WCAP-11572 and WCAP-11555.
September 22, 1987	Letter from licensee concerning 10 CFR 21 item regarding Limitorque SMB-0-25 operator key failure.
September 22, 1987	Letter from licensee concerning preliminary response to Generic Letter 87-12, with regard to loss of residual heat removal while the reactor coolant system is partially filled.
September 22, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-48 and 50-499/87-48 covering period of July 5-September 4, 1987.
September 23, 1987	Letter from licensee concerning turbine overspeed protection.
September 23, 1987	Letter from licensee concerning proposed revision to Technical Specifications standby diesel generator acceleration and equivalent frequency.
September 23, 1987	Letter from licensee concerning licensee event report regarding inoperable unit vent radiation monitors.
September 24, 1987	Letter from licensee forwarding security event report regarding vital area door that was not properly secured.
September 25, 1987	Letter from licensee forwarding advance copy of Revision 6 to emergency plan, per 10 CFR 50.54(q).
September 26, 1987	Letter from licensee concerning licensee event report regarding acutator motor shaft-to-pinion keys sheared because of incorrect and defective material.
September 28, 1987	Letter from licensee responding to Notice of Violation 87-27-01 dated August 28, 1987.
September 30, 1987	Letter from licensee concerning second interim report on cooling of the standby diesel generator high voltage cubicle panels.

September 30, 1987	Letter from licensee forwarding security event report regarding badge/key card set outside protected area.
September 30, 1987	Letter from licensee concerning monthly operating report - September 1987.
October 2, 1987	Letter from licensee concerning licensee event report regarding control room ventilation autoactuation to recirculation mode as a result of personnel error and incorrect operator response.
October 2, 1987	Letter from licensee concerning licensee event report regarding control room ventilation actuation to recirculation mode as a result of loss of sample flow to a control room ventilation radiation monitor.
October 2, 1987	Letter from licensee concerning status of Region IV open items.
October 5, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-51 and 50-499/87-51 covering period of August 3-7, 1987.
October 5, 1987	Letter from licensee concerning request for schedular exemption from 10 CFR 50.71(e) requirements to allow delay in submittal of updated FSAR until 1 year after issuance of Unit 2 operating license.
October 6, 1987	Letter from licensee concerning licensee event report regarding a control room ventilation actuation to recirculation mode as a result of toxic gas monitor defective flow switch.
October 6, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-56 and 50-499/87-56 covering period of August 31-September 4, 1987.
October 6, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-30 and 50-499/87-30 covering periods of November 11-19, 1986 and April 20-May 22, 1987.
October 8, 1987	Letter from licensee concerning the issuance of an incorrect badge/key card set to an employee.
October 8, 1987	Letter from licensee concerning security event report regarding the failure of the electronic security system and inadequate compensatory measures.
October 8, 1987	Motion to quash subpoena and motion for protective order; subpoena issued by R. D. Martin on September 22, 1987 should be quashed because Mr. Stites was not properly served, witness fees and transportation costs were not provided, and subpoena was issued in bad faith.

October 9, 1987	Letter from licensee concerning security event report regarding an employee who left the protected area with his badge/key card set.
October 9, 1987	Letter from licensee concerning response to NRC Inspection Report open item (498/8630-04), "Radioactive Material Transport Quality Assurance Program."
October 9, 1987	Letter from licensee providing status report on distribution of tone alert radios in emergency planning zone.
October 14, 1987	Letter from licensee concerning security event report regarding an employee who left the protected area with his badge/key card set.
October 14, 1987	Letter to licensee documenting a meeting held on September 18, 1987 in the Region IV office regarding the security program and a leak at the flange between the primary safety relief valve and the pressurizer at Unit 1.
October 14, 1987	Letter to licensee informing that enclosed criteria will be used by Region IV in making a determination of the operability of the intrusion detection system.
October 15, 1987	Letter from licensee concerning interim report on Class 1E cable splices.
October 16, 1987	Letter from licensee concerning change in essential ac lighting system acceptance test summary.
October 16, 1987	Letter from licensee responding to NRC September 17, 1987 letter regarding deviation noted in Inspection Reports 50-498/87-41 and 50-499/87-41.
October 16, 1987	Letter from licensee responding to NRC September 17, 1987 letter regarding violation noted in Inspection Reports 50-498/87-40 and 50-499/87-40.
October 19, 1987	Notice of October 23, 1987 licensee meeting in Bay City, Texas, to discuss leaking tubes in component cooling water heat exchangers.
October 19, 1987	Letter to licensee concerning final exercise report from the Federal Emergency Management Agency (FEMA).
October 19, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-57 and 50-499/87-57 covering period of September 14-18, 1987.
October 21, 1987	Letter from licensee concerning revision of the security personnel training and qualification plan.

October 21, 1987	Letter from licensee confirming October 23, 1987 meeting at site to discuss engineering analysis regarding leaking tubes in component cooling water/essential cooling water heat exchangers.
October 21, 1987	Notice of October 30, 1987 meeting in Bethesda, Maryland, to discuss improvements in security at South Texas Unit 1.
October 22, 1987	Letter from licensee concerning pump and valve inservice test program.
October 22, 1987	Letter from licensee concerning change in moveable incore detector test summary.
October 22, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-50 and 50-499/87-50 covering period of August 3-31, 1987.
October 23, 1987	Order granting the NRC the additional time requested to respond to motion to quash subpoena of E. Stites, per October 8, 1987 order.
October 23, 1987	Letter from licensee concerning final report on standby diesel generator fuel injection nozzles.
October 26, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-61 and 50-499/87-61 covering period of October 7-8, 1987.
October 29, 1987	NRC staff consents to motion to quash subpoena filed by E. Stites. Staff concedes possibility of deficiencies in service of subpoena to Stites and therefore does not oppose motion to quash.
October 29, 1987	Letter from licensee concerning Regulatory Guide 1.75 - physical separation of electric circuits, Wyle test results.
October 30, 1987	Letter from licensee concerning change in safety-related heat tracing preoperational test.
October 30, 1987	Letter to licensee acknowledging receipt of September 17, 1987 letter informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-39 and 50-499/87-39.
November 2, 1987	Letter from licensee concerning 10 CFR 21 item regarding component cooling water heat exchangers.
November 10, 1987	Letter to licensee concerning the FEMA evaluation of the South Texas Project, April 8, 1987 exercise.
November 12, 1987	Letter from licensee concerning essential cooling pond seepage.

November 12, 1987	Letter from licensee concerning proposed revision to Technical Specifications regarding Plant Operations Review Committee meeting minutes.
November 12, 1987	Letter from licensee concerning proposed revision to Technical Specifications regarding composition of Nuclear Safety Review Board.
November 12, 1987	Letter from licensee concerning proposed revision to Technical Specifications 3.0.4, 4.9.3, and 4.0.4 in accordance with Generic Letter 87-09.
November 12, 1987	Letter from licensee concerning application for amendment to License NPF-71 and FSAR allowing response time of 8 seconds for overtemperature delta-T and overpower delta-T instrumentation based on supporting analysis discussed in enclosed safety evaluation.
November 17, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-58 and 50-499/87-58 covering period of September 9-October 16, 1987.
November 17, 1987	Letter from licensee concerning application fee submittal for evaluation of 10 CFR 71 quality assurance program.
November 17, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-67 and 50-499/87-67 covering period of October 19-22, 1987.
November 17, 1987	Letter from licensee concerning resolution of license condition.
November 18, 1987	Letter from licensee documenting October 23, 1987 meeting at South Texas regarding utility's description of component cooling water design change needed to fix flow-induced vibration problem.
November 18, 1987	Letter to licensee stating that October 8, 1987 changes to emergency plan are consistent with 10 CFR 50.54(q) and 10 CFR 50, Appendix E, and are acceptable.
November 19, 1987	Letter to licensee acknowledging receipt of September 28, 1987 letter informing the NRC of steps taken to correct violations noted in Inspection Reports 50-498/87-27 and 50-499/87-27.
November 20, 1987	Letter from licensee concerning revisions to FSAR Section 14.2 regarding loss-of-offsite-power test and containment heating, ventilation, and air conditioning penetration space exhaust subsystem test.

November 20, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-68 and 50-499/87-68 covering period of October 19-November 6, 1987.
November 20, 1987	Letter from licensee concerning NRC October 22, 1987 letter regarding violations noted in Inspection Report 50-498/87-01.
November 23, 1987	Letter to licensee forwarding Inspection Reports 50-498/87-43 and 50-499/87-43 covering period of June 22-August 20, 1987.
November 23, 1987	Letter from licensee concerning control room design review status.
November 25, 1987	Letter from licensee concerning final report on the cooling of the standby diesel generator high voltage cubicle panels.
November 27, 1987	Letter to licensee forwarding Investigation Reports 4-85-015 and 4-85-018.
November 30, 1987	Letter from licensee concerning monthly operating report - November 1987.
December 1, 1987	Letter from licensee concerning additional information on increased resistance temperature detector (RTD) response time.
December 1, 1987	Letter from licensee concerning quality assurance program for the design and construction phase of the South Texas Project.
December 2, 1987	Letter from licensee concerning control room ventilation actuation to recirculation mode as a result of inadvertent switch operation.
December 3, 1987	Letter from licensee concerning first interim report on residual heat removal system valve installation.
December 9, 1987	Letter from licensee concerning sixth interim report on Veritrak transmitters.
December 9, 1987	Letter from licensee concerning supplement to the request for proposed revision to Technical Specifications and FSAR with regard to RTD response time.
December 11, 1987	Letter from licensee concerning licensee event report on high head safety injection system inoperablity as a result of personnel error.

December 11, 1987	Letter from licensee concerning the proposed revision to Technical Specifications 3.0.4 and 4.0.3 in accordance with Generic Letter 87-09.
December 12, 1987	Letter from licensee concerning licensee event report on a control room ventilation actuation to recirculation mode as a result of the detection of paint fumes by a toxic gas monitor.
December 14, 1987	Summary of December 2, 1987 meeting to discuss causes and modifications relative to pipe failures in the auxiliary feedwater system at South Texas Unit 1.
December 14, 1987	Letter from licensee concerning application for amending Technical Specifications related to tendons surveillance requirements.
December 15, 1987	Letter from licensee concerning annotated revisions to FSAR Section 17.2, "Quality Assurance During the Operations Phase."
December 15, 1987	Letter to licensee summarizing December 1, 1987 meeting in Region IV offices with utility concerning program for upgrading closed-circuit telev',ion system.
December 16, 1987	Letter to licensee concerning exemption related to the submittal of updated FS/R.
December 16, 1987	Letter from licensee concerning final report on Class 1E cable splices.
December 17, 1987	Letter from licensee concerning additional questions on the licensing fees in Invoices D0155, D0156, G0269, and G0270.
December 18, 1987	Letter from licensee concerning Revision 01 to the licensee event report on a control room ventilation actuation to recirculation mode as a result of the detection of paint fumes by a toxic gas monitor.
December 21, 1987	Letter from licensee concerning licensee event report on initiation of cooldown as a result of inoperability of two essential chiller units.
December 21, 1987	Letter from licensee concerning licensee event report on slave relay surveillance deficiency as a result of personnel error.
December 21, 1987	Letter from licensee concerning licensee event report on pressurizer low pressure safety injection setpoint that was too low as a result of a procedural error.

December 21, 1987 Letter from licensee concerning Regulatory Guide 1.75 - physical separation of electric circuits, Wyle test results.

December 22, 1987 Letter from licensee concerning licensee event report on control room ventilation actuation to recirculation mode as a result of the failure of a toxic gas monitor computer chip.

December 22, 1987 Letter from licensee concerning anticipated transients without scram mitigating system actuation circuitry.

December 22, 1987 Letter from licensee concerning first quarterly installment of fiscal year 1988 annual fee pursuant to 10 CFR 171.

December 23, 1987 Letter to licensee forwarding partially withheld Inspection Reports 50-498/87-54 and 50-499/87-54 covering period of September 8-11, 1987.

December 23, 1987 Letter to licensee forwarding partially withheld Inspection Reports 50-498/87-66 and 50-499/87-66 covering period of October 19-23, 1987.

December 23, 1987 Letter to licensee forwarding partially withheld Inspection Reports 50-498/87-52 and 50-499/87-52 covering period of August 24-28, 1987.

December 23, 1987 Letter from licensee concerning licensee event report on initiation of cooldown as a result of inoperability of two trains of containment spray.

December 23, 1987 Letter from licensee concerning withdrawal of application for authorization to use respirator for protection against radioiodine.

December 23, 1987 Letter from licensee concerning safeguards event report regarding a former employee who gained access to the protected area.

December 23, 1987 Letter from licensee providing additional information on thermowall-mounted RTDs.

December 24, 1987 Letter from licensee concerning auxiliary feedwater hydraulic transients.

December 28, 1987 Letter to licensee transmitting staff evaluation of containment purge and vent valves.

December 30, 1987 Letter from licensee concerning Pump and Valve Inservice Test Plan, Revision 2.

December 31, 1987 Letter from licensee concerning interim response to NRC Bulletin 87-001 - thinning of pipe walls in nuclear power plants.

December 31, 1987	Letter from licensee concerning operational readiness review.
January 4, 1988	Letter from licensee concerning the significant hazards evaluation for the proposed change to tendon surveillance requirements.
January 5, 1988	Letter from licensee concerning licensee event report on hydraulic transients in the auxiliary feedwater system as a result of a design error.
January 5, 1988	Letter from licensee concerning bottom-mounted instrument (BMI) thimble vibration.
January 7, 1988	Letter from licensee concerning Licensee Event Report 87-023 regarding loose valve-shaft-to-actuator-drive keys in motor-operated valves supplied by Rockwell International.
January 7, 1988	Letter from licensee concerning Licensee Event Report 87-024 regarding control room ventilation actuation to recirculation mode as a result of inadvertent operation of pushbutton by technician.
January 7, 1988	Letter from licensee concerning Licensee Event Report 87-022 regarding inoperability of both control room toxic gas monitors.
January 8, 1988	Letter from licensee concerning Licensee Event Report 87-025 regarding standby diesel generator actuation.
January 8, 1988	Letter from licensee concerning Licensee Event Report 87-021 regarding actuation of engineered safety features load sequencer and standby diesel generator.
January 11, 1988	Letter from licensee concerning Licensee Event Report 87-026 regarding degraded undervoltage coincident with a safety injection circuitry surveillance deficiency as a result of a deficient procedure.
January 11, 1988	Letter to licensee forwarding Inspection Reports 50-498/87-59 and 50-499/87-59 covering periods of September 21-25 and October 5-9, 1987.
January 18, 1988	Letter from licensee concerning main feedwater hydraulic transients.
January 22, 1988	Letter from licensee concerning essential cooling pond seepage.
January 28, 1988	Letter from licensee concerning proposed Technical Specification revision regarding composition of Plant Operations Review Committee.

January 28, 1988	Letter from licensee concerning proposed Technical Specification revision regarding offsite and onsite organization.
February 3, 1988	Letter from licensee concerning BMI thimble tubes.
February 5, 1988	Letter from licensee concerning inservice testing program.
February 11, 1988	Letter from licensee concerning proposed Technical Specification revision regarding high head safety injection pumps.
February 18, 1988	Letter from licensee concerning containment isolation system.
February 19, 1988	Letter from licensee concerning auxiliary feedwater system.
February 19, 1988	Letter from licensee concerning main feedwater system.
February 19, 1988	Letter from licensee forwarding Revision 8 of emergency plan.
March 10, 1988	Letter from licensee concerning proposed Technical Specification revision regarding Nuclear Safety Review Board.
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APPENDIX B

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APPENDIX D

ACRONYMS AND INITIALISMS

AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
ASME	American Society of Mechanical Engineers
BMI	bottom-mounted instrument
BNL	Brookhaven National Laboratory
CCTV	closed-circuit television
CFR	Code of Federal Regulations
COA	City of Austin
CPL	Central Power and Light Company
CPS	City Public Service Board of San Antonio
CVCS	chemical and volume control system
DNBR	departure from nucleate boiling ratio
ECP	essential cooling pond
ECWIS	essential cooling water intake structure
EG&G	EG&G Idaho, Inc.
EOP	emergency operating procedure
FAR	false alarm rate
FBCV	feedwater bypass control valve
FEMA	Federal Emergency Management Agency
FIBV	feedwater isolation bypass valve
FPBV	feedwater preheater bypass valve
FSAR	Final Safety Analysis Report
GAP	Government Accountability Project
GDC	general design criterion(a)
HHSI	high head safety injection
HL&P	Houston Lighting and Power Company
IDS	intrusion detection system
IE	Office of Inspection and Enforcement
IST	inservice testing
IVC	isolation valve cubicle
LBB	leak before break
LHSI	low head safety injection
LOCA	loss-of-coolant accident

MFW	main feedwater
MSL	mean sea level
NAR	nuisance alarm rate
NRC	U.S. Nuclear Regulatory Commission
OPDT	overpower delta-T
OTDT	overtemperature delta-T
PCT	peak cladding temperature
PORC	Plant Operations Review Committee
RCCA	rod cluster control assembly
RCS	reactor coolant system
RTD	resistance temperature detector
SER	Safety Evaluation Report
SGTR	steam generator tube rupture
SI	safety injection
SSER	Supplemental Safety Evaluation Report
TER	Technical Evaluation Report
TORAP	turbine overspeed reliability assurance program

APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANT

This Supplemental Safety Evaluation Report is the product of NRC staff and its consultants. The NRC staff members and consultants listed below were principal contributors to this report.

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APPENDIX Y

TECHNICAL EVALUATION OF
INSERVICE TESTING PROGRAM, REVISION 2

LETTER REPORT, TECHNICAL EVALUATION OF REVISION 2
CHANGES FOR PUMP AND VALVE INSERVICE TESTING PROGRAM,
SOUTH TEXAS PROJECT ELECTRICAL GENERATING STATION, UNIT 1

This letter report documents EG&G Idaho's review of South Texas Project Electric Generating Station, Unit 1, IST program, Revision 2, as described and forwarded to the NRC by a transmittal letter dated October 22, 1987.

Changes to the licensee's IST program, identified by revision bars on the affected pages, (i.e., valve additions or deletions) were reviewed utilizing the acceptance criteria and guidance contained in the following documents: the ASME Code Section XI, 1983 Edition with addenda thru Summer 1983 and Code interpretations when applicable, the Code of Federal Regulations 10CFR50, the Standard Review Plan, Section 3.9.6, and the Draft Regulatory Guide and Value/Impact Statement titled, "Identification of Valves for Inclusion in Inservice Testing Programs".

The licensee's amended Cold Shutdown Justifications No. RR-21 and RR-32 and additional Relief Requests Nos. RR-5, 6, 7, 8, 46, and 48 were evaluated to determine if testing the affected components in accordance with the Code requirements would be impractical, whether the licensee's proposed testing would provide a reasonable alternative to the Code requirements or whether it would place an unreasonable burden on the licensee if the Code requirements were imposed. Additionally, pump Relief requests Nos. RR-3 and RR-6 have been deleted from the IST program.

The licensee has also provided in their revised IST program valve tables the limiting values of full-stroke times for their power operated valves in accordance with IWV-3413(a).

Conference calls were held on December 2, 3, and 14, 1987, with Houston Lighting and Power Company, NRC, and EG&G Inc., representatives to

discuss the changes to the IST program which were considered to be unacceptable or where further information was necessary. These topics are addressed in Appendix A of this report.

In conclusion, the South Texas Project Electric Generating Station, Unit 1, IST program, Revision 2, is in accordance with the established Nuclear Regulatory Commission requirements with exceptions as noted in this report.

1. PUMP TESTING PROGRAM

The Houston Lighting and Power Company bases for requesting relief from the pump testing requirements and the reviewers evaluation of these requests are summarized below.

1.1 All Pumps in the IST Program

1.1.1 Range of Vibration Analyzers, Pump Relief Request RR-5

1.1.1.1 Relief Request. The licensee has requested relief from the requirements of Section XI, Paragraph IWP-4120, full scale range of instruments, for the measurement of pump vibration for all pumps in their IST program. The licensee has proposed to utilize either portable vibration indicators which exceed the range requirements but provide an overall readout repeatability within the limits of Table IWP-4110-1 or the permanently installed instrumentation during quarterly pump testing.

1.1.1.1.1 Licensee's Basis for Requesting Relief--Portable vibration indicators have selectable ranges in overlapping scales (multiples of 1 and 3 full scale). It is possible to have an indicated vibration which, in order to read on an available scale, will not be in the range of the instrument required by IWP-4120. The portable vibration indicators, which provide overall readout repeatability within the accuracy limits of Table IWP-4110-1, will be used to obtain vibration data except when permanently installed instrumentation is used.

1.1.1.1.2 Evaluation--Due to the wide variation in pump vibration measurements encountered on the safety-related pumps in the licensee's IST program it is not practical to obtain instruments which can meet the range requirements specified in Section XI, Paragraph IWP-4120, for the measurement of pump vibration for each affected pump. Some pumps could have reference vibration measurements that are sufficiently small that the allowable instrument range of three times the reference value, would not reach the Code

specified alert and required action limits. The licensee's proposal to use portable vibration indicators which may exceed the range requirements in some cases, however, which have indication repeatability which meets the accuracy requirements as specified in Table IWP-4110-1 provides a reasonable alternative to the Code requirements.

Based on the determination that the Code requirements are impractical and that the licensee's proposed alternative testing provides a reasonable alternative to the Code requirements and considering the burden on the licensee if the Code requirements were imposed relief should be granted as requested.

1.1.2 Range of Vibration Analyzers, Pump Relief Request RR-6

1.1.2.1 Relief Request. The licensee has requested relief from the requirements of Section XI, Paragraph IWP-4120, full scale range of instruments, for the measurement of pump vibration for the residual heat removal (RHR) and centrifugal charging pumps. The licensee has proposed to utilize the permanently installed on-line instrumentation which does not meet the range requirements of IWP-4120 but provides an overall readout repeatability within the limits of Table IWP-4110-1 and provides an alarm at the "alert" limit.

1.1.2.1.1 Licensee's Basis for Requesting Relief--The centrifugal charging pumps (located in the mechanical auxiliary building) and the residual heat removal pumps (located in the reactor containment building) are in areas of high radiation. For ALARA considerations, the vibration monitoring system (located in the control room) is used to measure vibration amplitude. The vibration monitoring system is an on-line system which constantly monitors the machine and provides alarms when the alert limits are reached. The full scale range of each instrument is fixed and the above requirement could be exceeded. Rescaling the instrument to meet the requirements of IWP-4120 for a low reference value would impair the ability of the system to monitor the machine up to the severity limit determined by size, speed, and application. The vibration monitoring system will be used

to obtain vibration data for the RHR and centrifugal charging pumps. The system provides overall readout repeatability within the accuracy limits specified in Table IWP-4110-1 with indiction in increments of at least 0.2 mils. If the vibration monitoring system is unavailable, portable vibration indicators will be used as described in RR-5 (in the STP-1 IST program).

1.1.2.1.2 Evaluation--Due to the wide variation in pump vibration measurements that may be encountered on these pumps it is not practical to obtain instruments or rescale the on-line instruments to meet the range requirements specified in Section XI, Paragraph IWP-4120, for the measurement of pump vibration. These pumps could have reference vibration measurements sufficiently small that the allowable instrument range of three times the reference value, would not reach the Code specified alert and required action limits. Further, the licensee is using an on-line system to continuously monitor these pumps' condition with alarms at the "alert" level which surpasses the Code requirements to take these measurements only on a quarterly basis. The licensee's proposal to use an installed vibration monitoring system which may exceed the range requirements of IWP-4120 in some cases, however, which has indication repeatability which meets the accuracy requirements as specified in Table IWP-4110-1 and provides alarms upon reaching the "alert" level provides a reasonable alternative to the Code requirements.

Based on the determination that the Code requirements are impractical and that the licensee's proposed alternative testing provides a reasonable alternative to the Code requirements and considering the burden on the licensee if the Code requirements were imposed relief should be granted as requested.

1.2.1 Range of Vibration Analyzers, Pump Relief Request RR-7

1.2.1.1 Relief Request. The licensee has requested relief from the requirements of Section XI, Paragraph IWP-4120, for the measurement of pump vibration in units of displacement amplitude, for all pumps in the IST program with the exception of the RHR and centrifugal charging pumps, and proposed to evaluate pump operability based on pump vibration velocity.

1.2.1.1.1 <u>Licensee's Basis for Requesting Relief</u>--The use of a velocity standard, rather than a displacement standard, is more indicative of pump condition and is industry accepted. At least one velocity measurement (in/sec unfiltered peak) shall be read during each inservice test. The frequency response range of the vibration measuring transducers and the readout system shall be one-half minimum pump rotational speed to at least 1,000 Hertz with an accuracy of at least plus or minus 5%. All other requirements of IWP-4510 and IWP-4520 shall be complied with. Allowable ranges of vibration velocity for pump testing shall be as follows:

	Test Quantity	Acceptable Range	Alert Range	Required Action Range
1.	V_t when $0 <= V_{r1} <= 0.05$ in/sec	0 to 0.075 in/sec	0.075 to 0.1 in/sec	>0.1 in/sec
2.	V_t when $0.05 <= V_{r2} <= 0.1$ in/sec	0 to 0.15 in/sec	0.15 to 0.2 in/sec	>0.2 in/sec
3.	V_t when $0.1 <= V_{r3} <= 0.15$ in/sec	0 to 0.2 in/sec	0.2 to 0.25 in/sec	>0.25 in/sec
4.	V_t when $0.15 <= V_{r4} <= 0.25$ in/sec	0 to 0.285 in/sec	0.285 to 0.314 in/sec	>0.314 in/sec

<u>Definitions</u>: V_r = Reference velocity measurement (in/sec unfiltered peak).
V_t = Surveillance test velocity measurement (in/sec unfiltered peak).

1.2.1.1.2 Evaluation--The licensee has proposed to utilize pump vibration velocity measurements in lieu of pump vibration displacement amplitude measurements for the determination of pump operability for all pumps in the IST program with the exception of the RHR and the centrifugal charging pumps. Vibration measurements in units of velocity are more sensitive to small changes in pump performance which can be indicative of developing mechanical problems. These velocity measurements detect the high amplitude vibration that can indicate major mechanical problems such as unbalance or misalignment. These velocity measurements also detect the low amplitude, high frequency vibration caused by bearing wear that usually goes undetected by simple displacement measurements.

The acceptance criteria that the licensee has proposed for the alert and required action ranges provides a reasonable alternative to the Code requirements for the detection of pump degradation. However, the measurement of vibration in units of velocity in only one direction on the pumps' housing may not provide an adequate alternative. To adequately assess the continued operability of these pumps utilizing pump vibration velocity measurements the measurements should be taken, to the extent practical, in areas readily duplicated during subsequent inservice tests as follows:

Centrifugal pumps:

Measurements should be taken in a plane perpendicular to the shaft in two orthogonal directions on all accessible pump bearing housings and in the axial direction on all accessible thrust bearing housings.

Vertical line shaft pumps:

Measurements should be taken on the upper motor bearing housing in three orthogonal directions (at least one of these measurements should be in the axial direction).

Reciprocating pumps:

Measurements should be taken on the crankshaft bearing housing at a location approximately perpendicular to the line of plunger travel and the crankshaft.

Based on the determination that the licensee's proposed alternative testing provides a reasonable alternative to the Code requirements which will be more indicative of changes in pump performance and considering the burden on the licensee if the Code requirements were imposed relief should be granted as requested provided the licensee takes pump bearing vibration velocity measurements as discussed above.

1.3.1 <u>Pump Bearing Temperature Measurement, Pump Relief Request RR-8</u>

1.3.1.1 <u>Relief Request</u>. The licensee has requested relief from the requirements of Section XI, Paragraph IWP-3300, for the annual measurement of pump bearing temperature for all pumps in the IST program and proposed that the quarterly measurement of pump vibration amplitude in accordance with the Code requirements provides the necessary information to warn of an impending pump malfunction.

1.3.1.1.1 <u>Licensee's Basis for Requesting Relief</u>--The yearly temperature measurement will not provide significant information about pump conditions. Industry experience has shown that bearing temperature changes caused by degrading bearings occur only after major degradation has occurred at the pump. Prior to this major pump degradation, the vibration measurement would provide the necessary information to warn of an impending malfunction. Deletion of this measurement will not have a significant effect on pump evaluation since vibration amplitude is measured quarterly. Vibration amplitude will be measured quarterly as required by the Code.

1.3.1.1.2 <u>Evaluation</u>--The licensee has proposed to delete the annual measurement of pump bearing temperature for all pumps in the IST program and to measure pump vibration amplitude quarterly as required by the Code. The licensee has not demonstrated that the measurement of pump bearing

temperatures for pumps with installed bearing temperature detectors or with accessible bearing housings is impractical. Further, it has not been demonstrated that the annual measurement of pump bearing temperatures is excessively burdensome to the licensee.

Based on the determination that the Code requirements are not impractical and that the licensee's proposed alternative testing does not provide a reasonable alternative to the Code requirements and considering the burden on the licensee if the Code requirements were imposed relief should not be granted as requested.

2. VALVE TESTING PROGRAM

The Houston Lighting and Power Company bases for requesting relief from the valve testing requirements and the reviewer's evaluation of these requests are summarized below and grouped according to system and valve Category.

2.1 Post Accident Sampling System

Category A Valves

2.1.1 Valve Relief Request RR-46

2.1.1.1 Relief Request. The licensee has requested relief from the verification of remote valve position indication accuracy requirements of Section XI, Paragraph IWV-3300, for valves AP-FV-2455 and 2455A. reactor coolant system sample valves, which are enclosed solenoid operated valves whose stem position cannot be directly observed to verify actual disk position, and proposed to determine stem position by observing system response to valve position changes.

2.1.1.1.1 Licensee's Basis for Requesting Relief--These valves, AP-FV-2455 and AP-FV-2455A, are solenoid valves for which stem movement cannot be directly observed. These are redundant valves in series and operate simultaneously from a single switch with one set of indicating lights. The valves are stroked and timed during normal inservice testing using the remote indicating lights. Open and closed indication is actuated by the limit switches of each valve wired in series. Therefore, remote position indication is based on the slowest valve. Since these redundant valves cannot be exercised separately (unless leads are lifted, temporary 125 VDC power is supplied to the disabled valve to maintain it in the open position and the jumpers are placed across the disabled valve's limit switches) the valves will be stroked simultaneously and remote position verified by observing system flow is initiated and then secured.

2.1.1.1.2 Evaluation--These valves, AP-FV-2455 and 2455A are solenoid operated valves in the post accident sampling system with no provision for observation of stem position without disassembly of the solenoid operator.

Due to their enclosed construction, no practical method exists to observe the stem position locally (at the valve) for verification of remote position indication accuracy. However, the licensee's proposal to verify the position of these valves by observing system flow and cessation of flow as an alternative to actual valve stem position provides a positive method of determining valve disk position and provides a reasonable alternative to the Code requirements

Based on the determination that the Code requirements are impractical and that the licensee's proposed testing provides a reasonable alternative to the Code requirements and considering the burden on the licensee if the Code requirements were imposed relief should be granted as requested.

2.2 Safety Injection System

Category A/C Valves

2.2.1 Valve Relief Request RR-48

2.2.1.1 Relief Request. The licensee has requested relief from the exercising requirements of Section XI, Paragraph IWV-3521, for valves XSI-0005A, 0005B, 0005C, 0030A, 0030B, and 0030C the high and low head safet injection (HHSI and LHSI) pump discharge check valves and proposed to perform a partial-stroke exercise of these valves quarterly and to verify the full-stroke capability of these valves by the performance of a full-flow test during refueling outages.

2.2.1.1.1 Licensee's Basis for Requesting Relief--These check valves can only be exercised (full-stroke) by simulating loss of coolant accident (LOCA) conditions (pumping into the reactor coolant system (RCS) with RCS at zero or very low pressure) in order to get full pump flows.

These check valves will be required to be exercised (partial stroke) at least once every three (3) months, provided the RCS pressure is above pump shutoff head, by running pumps at normal recirculation flows, and exercised (full-stroke) each refueling outage by injecting into the RCS with the vessel head off using the appropriate pump(s) at full flow.

2.2.1.1.2 Evaluation--Valves XSI-0005A, 0005B, 0005C, 0030A, 0030B, and 0030C, HHSI and LHSI pump discharge checks, cannot pass the flow necessary to verify their full-stroke capability during quarterly pump testing. The only flow path available to pass the flow necessary to full-stroke exercise these valves is into the reactor coolant system whose pressure during operation is above the shutoff head of these pumps. These valves can be partial-stroke exercised quarterly during pump testing utilizing a recirculation path to the refueling water storage tank. It would be impractical to either full or partial-stroke exercise these valves during cold shutdowns when RCS pressure is less than the shutoff head of the HHSI and LHSI pumps since flow would be into the reactor coolant system with insufficient surge volume available to accommodate the flow required to full-stroke these check valves. The licensee's proposal to partial-stroke exercise these valves quarterly during operations when the RCS pressure is above the shutoff head of the LHSI pumps and to full-stroke exercise these check valves during refueling outages when the reactor vessel head is removed provides a reasonable alternative to the Code requirements.

Based on the determination that the Code requirements are impractical and that the licensee's proposed alternative testing provides a reasonable alternative to the Code requirements and considering the burden on the licensee if the Code requirements were imposed relief should be granted as requested.

3. VALVES TESTED DURING COLD SHUTDOWNS

3.1 Main Feedwater System

Category B Valves

3.1.1 Cold Shutdown Justification RR-21

Valves FCV-0551, 0552, 0553, and 0554 cannot be full-stroke exercised quarterly during power operations without isolating feedwater from the steam generators causing undesirable power transients and possible turbine and reactor trip. These valves will be partial-stroke exercised during the course of normal plant operations by automatically stroking to maintain programmed steam generator level. Abnormal valve operations will be detected by steam generator level abnormalities. This valve will also be exercised (full-stroke) each cold shutdown, not to exceed once every three (3) months.

3.2 Safety Injection System

Category A/C Valves

3.2.1 Cold Shutdown Justification RR-32

Valves XSI-0010A, 0010B, and 0010C, high head safety injection check valves cannot be full or partial-stroke exercised quarterly during power operations since the shutoff head of the LHSI and HHSI pumps is below the operating pressure of the reactor coolant system and flow cannot be established through these valves. These valves will be full-stroke exercised during cold shutdowns and refueling outages, in accordance with the Code requirements, by momentarily diverting flow from the residual heat removal system through these valves into the RCS hot legs.

APPENDIX A

IST PROGRAM ANOMALIES IDENTIFIED DURING THE REVIEW

Conference calls were held on December 2, 3, and 14, 1987, with Houston Lighting and Power Company, NRC, and EG&G Inc., representatives to discuss the changes to the IST program which were considered to be unacceptable or where further information was necessary. These items are summarized below and may have an effect on the IST program content:

1. The reference to the bi-annual verification of remote valve position indication accuracy had been deleted from the IST program, Revision 2, valve tables for valves HCV-851, 852, 853, 864, 865, and 866. Paragraph IWV-3300 states that valves equipped with remote position indication must be observed at least once every two years to verify the position indication accuracy. The licensee stated that they would comply with IWV-3300 and revise their IST program valve tables to reflect this testing requirement.

2. Valves PC-6854, 6864, 6874, 6904, 6905, and 6906 have been added to the IST program. The IST program does not identify that these valves will have their remote position indication verified and the reviewer was uncertain if these valves would be fail-safe tested in accordance with the Code requirements. This was discussed and the licensee has agreed to perform both of these tests in accordance with the Code requirements and to revise the valve tables to reflect that it is in compliance with IWV-3300.

3. Valves FV-4450A and 4451A have been deleted from Revision 2 of the IST program. The licensee stated that these valves have had their power removed (passive valves) and that these valves do not perform a containment isolation function. If these valves do not perform a containment isolation function and need not be categorized A then they have no testing requirements and need not be included in the IST program.

4. Valve Relief Request RR-47 did not provide sufficient technical justification for relief from the Code requirements. The licensee has decided to withdraw this relief request and delete the reference to it from their IST program.

5. The technical justification provided in pump Relief Request No. RR-8 is not adequate to obtain relief from the applicable Code requirement. The licensee stated that RR-8 would be revised to propose performing pump vibration velocity measurements quarterly in lieu of annual bearing temperature measurements as required by the Code.

6. Valve relief request RR-36 no longer affects any valves in the IST program and may be deleted.

NRC FORM 335
(8-87)
NRCM 1102,
3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

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12. SUPPLEMENTARY NOTES
Docket Nos. 50-498 and 50-499

13. ABSTRACT (200 words or less)

In April 1986 the staff of the U.S. Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0781) regarding the application of Houston Lighting and Power Company (applicant and agent for the owners) for a license to operate South Texas Project, Units 1 and 2 (Docket Nos. 50-498 and 50-499). The facility is located in Matagorda County, Texas, west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. The first supplement to NUREG-0781 was issued in September 1986, the second supplement in January 1987, the third supplement in May 1987, and the fourth supplement in July 1987. This fifth supplement provides updated information on the issues that had been considered previously as well as the evaluation of issues that have arisen since the fourth supplement was issued. The evaluation resolves all the issues necessary to support the issuance of a full-power license for Unit 1.

14. DOCUMENT ANALYSIS - a. KEYWORDS/DESCRIPTORS
South Texas Project, Units 1 and 2
Safety Evaluation Report

b. IDENTIFIERS/OPEN ENDED TERMS

15. AVAILABILITY STATEMENT
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16. SECURITY CLASSIFICATION
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