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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

South Texas Project
Units 1 and 2
Docket Nos. STN 50-498, STN 50-499
Additional Information Regarding Proposed Special Test Exception 3.10.8
(TAC No. M92169/M92170)

Reference: 1. Letter from T. H. Cloninger to the Nuclear Regulatory Commission Document Control Desk dated May 1, 1995 (ST-HL-AE-5076)

2. Letter from T. H. Cloninger to the Nuclear Regulatory Commission Document Control Desk dated August 28, 1995 (ST-HL-AE-5141)

In Reference 1, the South Texas Project proposed a change to the South Texas Project Units 1 and 2 Technical Specifications that would incorporate a Special Test Exception for an allowed outage of up to 21 days per cycle for each Standby Diesel. In Reference 2, the South Texas Project responded to Nuclear Regulatory Commission questions regarding the justification and implementation of the proposed Special Test Exception. The Nuclear Regulatory Commission staff subsequently asked the South Texas Project to elaborate on some of the responses provided in Reference 2, and this submittal responds to that request.

The South Texas Project responses are attached. If you have any questions, please contact me at 512-972-7795, or Mr. A. W. Harrison at 512-972-7298.

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Director,
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Attachment: Response to Nuclear Regulatory Commission Questions

TSC-95\5208

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Response to Nuclear Regulatory Commission Questions

The South Texas Project believes that the responses to the questions below underscore the robustness of the station's design. Except for the response to Question 10, credit has not been taken for the Emergency Transformer and its associated 138 kV line. As described in the South Texas Project UFSAR, this line is independent from the normal power supplies to the ESF busses and is capable of providing power to any selected ESF bus. The proposed Special Test Exception requires the operability of this power source. Postulating an accident with a loss of off-site power and a single failure while in the Special Test Exception, and not crediting this required power source imposes an extraordinary set of conditions on the station. The capability to mitigate this condition as described in the submittals supporting the proposed Technical Specification change provides a high degree of confidence in its acceptability.

1. **Describe the basis for the assumption that there would be 1 train of containment sprays and fan coolers for any combination of two diesel generators failed or out of service. Confirm that for any combination of two diesel generators failed or out of service, there are no dependencies across trains that could disable the third train of containment sprays or fan coolers.**

A1. There are no dependencies in electrical power, instrumentation, or support systems across trains for the containment spray system. The containment spray trains share only the Refueling Water Storage Tank (RWST), the spray ring headers with nozzles, and some piping to the spray ring headers.

Total spray flow with one train would be slightly more than half the total two train spray flow. Pressure drop across the spray nozzles would be much less than 40 psid, resulting in a reduction in sprayed area and an increase in average spray droplet size. Effective initiation time would increase because the same volume of empty spray pipe and spray ring headers would be filled by one pump instead of two. The single spray pump would not run-out beyond the design pump curve. Note that this is an update to the information provided in the response to Question 7 in our August 28, 1995 letter (ST-HL-AE-5141)

The RCFC fans also have no dependencies in electrical power or instrumentation across trains. The dependency of the CCW system to support RCFC operation is described in the response to question 4.

2. Clarify whether the words "containment structural integrity limits" (p. 11 of ST-HL-AE-5141, Attachment 3) refer to the containment design pressure or some other limit, such as service level C.

A2. The containment structural integrity limits refer to the containment design pressure of 56.5 psig and containment structural accident temperature of 286°F.

3. Discuss why the number of fan coolers is reduced to one (rather than two) of six when only one safety train is available. What other failures or dependencies are involved?

A3. There are actually two fan coolers available with only one train in service, but the number was reduced to one by conservatively assuming that one of those two is inoperable. There is no deterministic reason for the assumption.

The other failures include reduced component cooling water flow to the fan coolers. This results in degraded fan cooler performance. Also, the containment spray flow rate is reduced to account for only one spray pump in operation.

4. Unless the operable train is the C train, one of the two CCW headers will not automatically isolate. Consistent with the STP PSA assumptions, this will result in loss of all CCW (at least until manual isolation can be completed). Justify why credit for any fan coolers is taken in the STP assessment, in view of the dependence of the fan coolers on CCW and the inability to restore CCW in the time-frame associated with the containment analyses. If loss of all fan coolers is possible under these conditions, provide an estimate of the peak pressure and temperature that would result for the design basis pipe break given 1 train of containment sprays and no fan coolers are operable.

A4. The CCW system contains five flow paths which are isolated by automatic valves upon receipt of a Safety Injection signal. The system also contains several non-ECCS components which remain in service intentionally following receipt of a Safety Injection signal. Without detailed analysis of the actual condition of the remaining train, the PSA conservatively assumed the loss of two CCW trains would lead to loss of the remaining train. However, analysis of the CCW system following a Safety Injection signal indicates the remaining CCW train will operate satisfactorily following a loss of power to any other two CCW trains.

Total CCW flowrate would be less than maximum CCW pump runout flow of 16,000 gpm. Flow rates to the ECCS components (RCFC Coils and RHR Heat Exchanger) would be 85 to 90% of design flow. Peak CCW supply temperature to the ECCS components would be approximately 130° F, which is somewhat higher than temperatures reported in the Safety Analysis Report, but is acceptable to support the ECCS components. The degraded performance of the RCFC's and RHR heat exchanger due to lower CCW flows and higher peak CCW temperatures have been accounted for in the estimates of containment pressure and temperature response.

The flow rate of the single CCW pump would be close to the specified design point of the pump and less than pump run-out. Flow through the CCW heat exchanger would be close to the flow specified in the design specification and less than the maximum flow capability of the heat exchanger. Flow rates to the ECCS components (Reactor Containment Fan Cooler Coils & RHR Heat Exchanger) would be 85 to 90% of design flow. CCW supply temperature to the ECCS components would be somewhat higher than temperatures reported in the Safety Analysis Report, but would be acceptable to support the ECCS components. The degraded performance of the RCFC's and RHR heat exchanger have been accounted for in the estimates of containment response.

Since the RHR Heat Exchangers are not required until the Safety Injection system switches to the recirculation mode, there is some time available for operator action to restore proper CCW alignment. The STP evaluations have not credited that action.

5. The response to Question 6 (p. 13 of ST-HL-AE-5141, Attachment 3) states that a review of the analysis of record shows sufficient margin to ensure the containment structure does not exceed its design parameters with only one safety train. Provide an estimate of the peak containment pressure and temperature that would result given operation of only one safety train (1 train of containment sprays and 1 fan cooler). Discuss whether similar margins would exist for the entire spectrum of accidents/pipe breaks considered in the design (i.e., Table 6.2.1.1-1 of the UFSAR).

A5. The containment structural design temperature is 286°F. The analysis of record that supports this temperature assumes a constant temperature of 323°F for approximately 500 seconds. For the limiting break size with one containment spray train and one fan cooler in operation, the estimated containment peak temperature is 329°F and the temperature profile is expected to remain above 286°F for about 300 seconds. This temperature profile is less severe than the temperature profile assumed in the analysis of record, therefore, the structural design temperature of 286°F will remain bounding.

The containment pressure with one spray train and one fan cooler in operation is estimated to be about 46 psig, which is less than the design pressure of 56.5 psig. Therefore, the design basis pressure remains valid and bounding.

For the entire spectrum of pipe breaks listed in UFSAR Table 6.2.1.1-1, sufficient margin to design is expected for all design basis accidents with only one safety train available.

Also, in the response to Question 6 in our letter dated August 28, 1995 (ST-HL-AE-5141), the South Texas Project stated that the equipment qualification doses resulting from only one train of containment spray operating might exceed existing limits. Subsequent evaluations have shown that the expected doses are within equipment qualification limits.

6. **Clarify whether a loss of instrument air is anticipated or likely given the loss of offsite power and unavailability/failure of two diesels.**

A6. A loss of Instrument Air (IA) is not anticipated or guaranteed given a loss of offsite power and the unavailability/failure of two diesel generators. The reason for this is as follows:

1) All instrument/service air compressors are powered from separate nonsafety electric buses. Also, one instrument air compressor is powered from a separate onsite Balance-of-Plant (BOP) diesel generator in the event of interruption of the normal power source.

2) The IA system air receiver is sized to meet the normal instrument air requirements for approximately 2 minutes after loss of compressor function.

3) A redundant air supply source for IA system is provided through the interconnection line from the service air system. The service air system supplies oil-free air to outlets throughout the plant and serves as a backup to the IA system in case of failure of the IA compressors.

The IA system performs no safety function. Failure of the system does not prevent safe shutdown of the reactor. Air operated valves are designed to go to their fail-safe position on loss of IA. Therefore, functions important to safety are not compromised. The proposed Special Test Exception imposes no new conditions on the Instrument Air system, and the STP analyses include no new assumptions regarding its availability.

7. **Most containment penetrations can be isolated by either an MOV or air operated valve, even with the loss of two diesels. Nevertheless, increased unavailability of diesel generators represents a decrease in defense-in-depth and reliability of the containment isolation system. In this regard, please provide the following:**

a. **a comparison of the containment isolation failure frequency with and without the requested technical specification change,**

A7a. Containment failure is modeled in the STP PSA as Top Events CI (< 3") and CP (> 3"), which are defined as failure to close at least one valve in each modeled containment penetration. The failure frequency for CI and CP including the requested Technical Specification Amendment is 8.80E-6/reactor-yr. and 1.85E-7/reactor-yr., respectively. The frequency for the Base Case is 6.12E-06/reactor-yr. and 1.27E-7/reactor-yr., respectively.

b. a listing of the penetrations with greatest contribution to containment isolation failure frequency and their respective contributions,

A7b. In the STP PSA the accident sequences, as defined by plant damage states, that make up the core damage frequency also provides information on containment isolation. Even though, containment isolation does not contribute to a core damage event, the calculation needed to obtain a containment isolation failure frequency is also performed as a part of the overall core damage frequency calculation. This is modeled as Top Events CI and CP as defined in the response to question 7a. The contribution of each penetration is shown below. The percent values shown in the table were calculated without the STE; however, the list is valid for showing the relative significance of the main contributors.

Penetration	Contribution (%)
Supplementary Containment Purge Supply and Exhaust (Top Event CP))	82.6*
Reactor Coolant Drain Tank Vent (Top Event CI)	1.7
Letdown and Seal Return Lines (Top Event CI)	3.1
RCDT to LWPS Hold Tank (Top Event CI)	2.2
RCS Pressurizer Relief Tank Vent (Top Event CI)	3.8
Containment Normal Sump Drain Line (Top Event CI)	2.3
Radiation Monitoring (Top Event CI)	4.3

* Primarily due to the time when the supplementary purge is open for containment purge.

The only penetration modeled in the PSA that was truncated in the results is the Pressurizer Relief Tank Post-Accident Sampling Line. The isolation line consists of a check valve and air-operated valve. The check valve is designed to allow flow into the containment and the air-operated valve is designed to fail close. This design provides for a highly reliable containment penetration.

c. an estimate of the reduction in containment isolation failure frequency and large release frequency that could be achieved if all containment purge/vent penetrations and any other large penetrations connected to the containment airspace are isolated at all times during the STE, and

A7c. Containment integrity will be maintained according to Technical Specification 3/4.6.1. Additionally, any containment purges that may be required by Technical Specification 3.6.1.4, during the STE will be strictly controlled. Although the requested analysis would show an improvement in containment performance, STP could not ensure that all containment purge/vent penetrations, etc. could be maintained isolated throughout the STE duration due to the operational requirements to maintain containment pressure within limits. Additionally, the amount of containment performance improvement that could be achieved given that all containment purge/vent penetrations, etc. are isolated would be approximately represented by the sum of the failure rates for valves to transfer to their fail-safe position which is a low contribution.

d. an assessment of the impact on operations of requiring key containment penetrations (as defined in [b.] above) to be isolated at all times during the STE.

A7d. See response to question Q7c. STP may be required to purge containment due to pressure build-up due to containment heating or negative pressure due to containment cooling in cold weather. Technical Specification 3.6.1.4 requires the plant to be in MODE 3 in 6 hours and COLD SHUTDOWN in the following 30 hours if the containment pressure cannot be restored to the -0.1 to +0.3 psig limits within 1 hour.

8. The response to Question 7 (p. 16 of ST-HL-AE-5141, Attachment 3) indicates that two systems modelled in the PSA have MOVs for both the inboard and outboard isolation function (and therefore would not be automatically isolated given the loss of the two diesels that provide power to these valves). However, the PSA may not have modelled all containment penetrations. Confirm that of the complete set of containment penetrations, the containment radiation monitoring and RCP seal return lines are the only lines whose isolation function would be compromised by loss of two diesels.

A8. In the development of the PSA a screening analysis of all containment penetrations was performed with respect to the leakage of radioactive materials from containment following an accident. Not all penetrations are addressed in the PSA based upon this screening. The PSA models penetrations that communicate directly with the RCS or the RCB atmosphere and require automatic closure of at least one valve. Penetrations that are normally closed by manual valves are not modeled.

Penetrations required to isolate in the event of an accident are:

- Containment Supplementary Purge Lines
- Containment Radiation Monitoring Lines
- Pressurizer Relief Tank Vent Line
- Pressurizer Relief Tank Post-Accident Sampling Line
- Reactor Coolant Drain Tank Vent Line
- RCDT to LWPS Holdup Tank Line
- Containment Normal Sump Drain Line
- Letdown and Seal Return Lines

The comprehensive screening analysis for containment penetrations is based upon Chapter 6 of the STP FSAR. This evaluation included the following considerations:

- Safety Function of the line through the penetration, i.e., Containment Spray, Safety Injection, etc.

- Whether or not the lines through the penetration communicate directly with the containment atmosphere or the reactor coolant system.

- Closed/Sealed system status during power operations.

- Periodically operated systems (i.e., Breathing Air system) with the containment isolation valves that are locked-closed when the system is not in use.

The PSA screening analysis for containment isolation function included all containment isolation lines. From this analysis, the only required containment isolation lines with MOVs for both sides of the penetration are the containment radiation monitoring and RCP seal return lines. Emergency operating procedures contain instructions to isolate these valves in the event of a loss of all AC power (Reference 0POP05-EO-EC00). In addition 0POP05-EO-EO00, "Reactor Trip or Safety Injection" requires confirmation of containment isolation if safety injection is initiated, and specifies operator action to isolate penetrations that are required to be closed.

9. Discuss the role of the containment radiation monitoring and RCP seal return lines and associated isolation valves following an event. Clarify whether these lines are intended to remain open to enable continued system operation.

A9. Containment radiation monitoring is used to initiate the containment ventilation isolation signal that will close the normal and supplemental purge valves on detection of high containment radiation. It has no post-accident function.

The Reactor Coolant Pump seal return line normally returns Chemical and Volume Control System water used to cool the RCP seals. The seal return is isolated on a Containment Phase A isolation signal. The seal return is not essential to maintaining CVCS to the RCP seals or for maintaining RCP seal integrity or function. STP accident analyses do not assume the availability of the RCPs or the seal return.

10. Given the time available before hydrogen recombiners are needed, describe the capabilities to cross-connect each recombiner to either of the alternate safety trains. Confirm that these connections could be completed or that an external recombiner could be installed in the available time.

A10. The proposed Special Test Exception requires the Emergency Transformer and associated 138 kV transmission line to be available. In the event of a loss of the preferred offsite power sources, the Emergency Transformer secondary may be aligned to any one of the three 4.16 kV ESF buses, including either bus powering a hydrogen recombiner.

The hydrogen recombiners would not be required for at least 11 days following a postulated design basis LOCA. Should a loss of all offsite power occur, restoration of offsite power to STP would be a high priority. The Electric Reliability Council of Texas (ERCOT) Black Start Guide states: "Priority should be given in restoring at least one circuit to nuclear power plants to provide offsite power for safe shutdown."

Thus, normal offsite power would be expected to be restored before hydrogen recombiner operation was required.

In the event of an extended loss of all offsite power sources, including the Emergency Transformer, two ESF buses may be powered by a single SDG. Plant Procedure 0POP04-AE-0001, "Loss of Any 13.8 kV or 4.16 kV Bus", defines the procedural steps for cross-connecting ESF Train B to either ESF Train A or Train C. Similar procedural steps would apply to cross-connection of any one ESF bus to either remaining ESF bus. The power consumption of one hydrogen recombiner is bounded by the loading limits previously analyzed for cross-connected ESF bus operation.

11. Page 10 of 17 of the August 28, 1995, supplement (Steam System Failures) says, "With only one train of safety injection, the return to power would increase slightly above the level in the analysis of record, thereby decreasing the margin to DNB. However, the increase in power would also result in a slightly higher RCS pressure, increasing the margin to DNB. Based on these competing effects and available margin to DNB, HL&P believes the DNB would not occur with only one train of safety injection available."

What method has the licensee used to determine that when operating with one safety injection train the subsequent decrease in margin to DNB is comparable to the increase in DNB margin caused by the slightly higher RCS pressure? How does operating with one safety injection train impact the current safety margins.

A11. The increase in DNB margin associated with an increase in RCS pressure is not expected to fully offset the decrease in DNB margin associated with the increase in reactor power for the steam line break event with one train of safety injection. Typically, the calculated DNB for the Steam Line Break event is significantly above the acceptance limit. For example the calculated DNBR for Unit 1, Cycle 5 and Unit 2, Cycle 5 is 2.61 and 2.04, respectively. This is against an acceptance limit of 1.495 using the W-3 correlation and penalties for the RCS flow anomaly. Therefore, sufficient DNB margin exists in the current analysis to offset the DNB penalty associated the anticipated increase in reactor power for the steam line break event with only one train of safety injection.

12. **Page 15 of 17 of the August 28, 1995 supplement (Component Cooling Water) says, "The systems dependent on CCW for cooling, as modeled in the PSA, are seal cooling for the Reactor Coolant Pump (RCP) using the thermal barriers, the Residual Heat Removal (RHR) system heat exchangers and pump motors , Reactor Containment Fan Coolers (RCFCs), and Charging (room and lube oil cooling)."**

    From UFSAR Section 5.4.7, it appears that the RHR heat exchangers are used for long-term cooling, (i.e., the second phase of normal plant cooldown). If so, and in the unlikely event that the CCW (and hence the RHR heat exchangers) were to be unavailable for up to 24 hours, as allowed by the licensee's proposed technical specifications, how would the reactor cooldown rate discussed in the UFSAR be affected?

A12 The response to Question 4 above discounts the potential for the loss of all three trains of CCW and its supported systems. The reactor cooldown rate will be acceptable with at least one train of CCW operable. The proposed Special Test Exception allows for 24 hours to restore the affected systems if both the other trains become inoperable while the plant is in the STE. However, with one or more trains of components inoperable while in the STE, the actual time allowed will be governed by the application of the Configuration Risk Management Program as described in the Bases for the STE In the case where both of the other trains are inoperable while the plant is in the STE, the CRMP would impose a much shorter allowed outage time than 24 hours.

13. **Page 12 of 17 says there are instances where the requirements of 10 CFR 50. 46 may not be met for large and medium break LOCAs ("the consequences of a LOCA would not be satisfied if the break was in the cold leg of the available safety train," and "for a very narrow range of breaks on the smaller range of the spectrum, it is assumed one HHSI pump may not be enough to keep up with the break flow and the RCS may not depressurize enough to reach the LHSI injection pressure").**

a. Are there any other plant configurations or operating procedures that would lessen the vulnerability of the area of piping in question?

A13a. The South Texas Project Emergency Operating Procedures for post-accident depressurization and cooldown provide the operator with direction and appropriate conditions for depressurizing the RCS in the event of an accident. In addition, the EOPs address conditions when core cooling is degraded or inadequate. Based on core exit thermocouple temperatures, 0POP05-EO-FRC1, "Response to Inadequate Core Cooling", and 0POP05-EO-FRC2, "Response to Degraded Core Cooling", direct the operators to depressurize the intact steam generators such that the RCS will reach accumulator and low head safety injection conditions.

b. Does the vulnerability area of piping (i.e., the cold leg) meet the leak-before-break criteria?

A13b. The area of vulnerability meets leak-before-break criteria. The South Texas Project Reactor Coolant System main loop and surge line piping has been analyzed and determined to meet leak-before-break criteria. NRC acceptance of these analyses is documented in the South Texas Project Safety Evaluation Report and its supplements (NUREG 0781).