TUELECTRIC

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GL-96-06

October 2, 1998

C. Lance Terry
Senior Vice President
& Principal Nuclear Officer

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445 AND 50-446
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION
ON LICENSE AMENDMENT REQUEST 96-006

REF:
1) TU Electric Letter, logged TXX-96434, from C. L. Terry to the NRC dated August 2, 1996,

2) NRC Letter from the T. J. Polich, NRR, to C. L. Terry, dated July 30, 1998,

Gentlemen:

Per Reference 1, TU Electric submitted a request to amend the CPSES Unit 1 Operating License (NPF-87) and CPSES Unit 2 Operating License (NPF-89) by incorporating changes that would increase the outage time allowed for a centrifugal charging pump to be out of service from 72 hours to 7 days for CPSES Units 1 and 2. On August 3, 1998, TU Electric received a request for additional information regarding License Amendment Request 96-006. Attachment 1 is the affidavit for this information supporting License Amendment Request 96-006. Attachment 2 provides commitments made in this correspondence. Attachment 3 provides our response to the information requested in Reference 2.

If you have any questions regarding the attached information, please contact Mr. J. D. Seawright at (254) 897-0140.

D029

This communication contains updated commitments regarding CPSES Units 1 and 2 as identified in Attachment 2.

Sincerely,

C. L. Terry

By: Roger D. Walker
Regulatory Affairs Manager

JDS/jds
Attachments

c - Mr. E. W. Merschoff, Region IV
Mr. T. J. Polich, NRR
Mr. J. I. Tapia, Region IV
Resident Inspector, CASES

Mr. Arthur C. Tate
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Texas Department of Public Health
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Austin, Texas 78704

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
Texas Utilities Electric Company	)	Docket Nos. 50-445
	)	50-446
(Comanche Peak Steam Electric	)	License Nos. NPF-87
Station, Units 1 & 2)	)	NPF-89

AFFIDAVIT

Roger D. Walker being duly sworn, hereby deposes and says that he is the Regulatory Affairs Manager of TU Electric, the licensee herein; that he is duly authorized to sign and file with the Nuclear Regulatory Commission this Request for Additional Information regarding License Amendment Request 96-006; that he is familiar with the content thereof; and that the matters set forth therein are true and correct to the best of his knowledge, information and belief.

Roger D. Walker

Roger D. Walker
Regulatory Affairs Manager

STATE OF TEXAS)
)
COUNTY OF Somervell)

Subscribed and sworn to before me, on this 2nd day of October, 1998.

Dayle R Peck Jesperson

Notary Public

The following new commitment was made in Attachment 3 to letter logged TXX98215:

CDF No.	Commitment
27162	Completion of the reviews and approvals by the TU Electric Station Operations Review Committee (SORC) and Offsite Review Committee (ORC) is expected by the end of October with submittal of the supplement to License Amendment Request 96-006 to the NRC in early November.

Additional PRA-Related Information Required for the Review of the Proposed Comanche Peak Charging Pump AOT Extension from 3 to 7 days

Comanche Peak used a risk argument to justify the proposed allowed outage time (AOT) extension for the centrifugal charging pumps (CCPs). The staff evaluation of the amendment generally follows the recently approved Regulatory Guide 1.174[1] and 1.177[2], in which a three-tiered approach has been identified for licensees to evaluate the risk associated with risk-informed modifications to technical specifications (TS). In short, Tier 1 is an evaluation of the impact on plant risk, Tier 2 is an identification of potentially high risk configurations, and Tier 3 is the establishment of an overall configuration risk management program (CRMP). Therefore, the following information is needed for the review of the requested application for CCP AOT extension.

Tier 1: Risk Impact and PRA Validity

1. **Provide the following risk measures for the staff review of the risk impact of the proposed change. The results from external events should be addressed quantitatively or qualitatively.**

   a. **Instantaneous CDF and Large Early Release Frequency (LERF) given a CCP is out of service. Discuss the difference in results between preventive maintenance and corrective maintenance.**

Response:

Internal Events
Instantaneous calculations were performed using the CPSES linked model with all test and maintenance set to 0.0. A CCP was then taken out of service consistent with the approach used for on-line risk determination. The results are:

- Instantaneous CDF = 4.79 E-05
- Instantaneous LERF = 1.09 E-06

External Events

For the consideration of external events in the response to this request for information, the fire and tornado results from the IPEEE were used, again with test and maintenance set to 0.0. The instantaneous value of CDF for external events was calculated as 4.94E-05.

There is no difference in instantaneous CDF and LERF between preventive maintenance and corrective maintenance for either internal or external events. The approach used to determine the instantaneous values sets the failure probability of the CCP to 1.0 in each case.

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[1] RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Current Licensing Basis"

[2] RG 1.177,"An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications"

b. Change in LERF due to the proposed change.

Response:

This response includes the change in LERF and the change in CDF resulting from the proposed change. The CDF is provided, along with a discussion of the change in approach TU Electric is using in the calculations compared to the original submittal.

When the original work was done, the objective was simply to demonstrate that the change was not risk significant. The criteria for the risk significance determination was the PSA Applications Guide for a permanent plant change. In the intervening period, Regulatory Guide 1.174 has been developed which puts emphasis on the absolute value and the cumulative impacts of a plant change. Consequently, the approach used to calculate the impacts was changed. In the original calculation, a very conservative, bounding approach was used to calculate the global impacts of the proposed change. That approach adjusted fails-to-run and fails-to-start failure modes in addition to the test and maintenance unavailability by various factors. The current approach adjusts only the test and maintenance unavailability. Although the extended AOT is intended for use with maintenance unavailability, it was conservatively decided that both test and maintenance would be adjusted for these calculations. This retains some significant conservatism in the calculations. The changes to CDF and LERF with and without changes to the test unavailability are included for comparison.

Internal Events

Changes in CDF and LERF due to the proposed change were calculated using the IPE linked model as follows: The maintenance unavailability was increased by the ratio 28.7/11.1 (2.59) to account for the estimated increase in maintenance unavailability based on the PLG database correlation which relates corrective maintenance duration to technical specification allowed outage time. The test unavailability was increased by the factor 168/72 (2.33). The results are:

	Maintenance Only	Test Only	Both Test and Maintenance
Delta CDF	7E-08	2E-08	9E-08
Delta LERF	1.9E-09	4E-10	2.3E-09

These results show that the global impacts of the proposed change considering internal events are very small.

External Events

The change in CDF for external events was estimated by using the IPEEE results and changing the values of the CCP test and maintenance segments accordingly, as described above for internal events. The results are:

	Maintenance Only	Test Only	Both Test and Maintenance
Delta CDF	2.1 E-07	4 E-08	2.5E-07
Delta LERF	5.37E-09	1.02E-09	6.39E-09

Delta LERF was estimated as the ratio of the change in CDF for fire-tornado to change in CDF for internal events multiplied by the change in internal events LERF. This approach is based on the results of the CPSES IPEEE containment performance evaluation which showed that the IPEEE did not introduce any new plant damage states nor did it result in fire-induced containment failures that occurred at a significantly higher frequency than noted in the IPE. This ratio is a statement that the plant damage states for IPEEE/IPE LERF are essentially the same and that the frequencies are proportional to the core damage frequencies for fire-tornado and internal events. This is conservative. In the CPSES Risk-Informed IST submittal, TU Electric presented arguments which show that the LERF for external events is proportionately much less than the IPE, relative to the CDF, primarily because the steam generator tube ruptures which contribute much to LERF in the internal events are not a consequence of fire and tornado.

2. Discuss, quantitatively or qualitatively, the averted risk (during transition and shutdown) stemming from being able to perform maintenance at power instead of during shutdown, which would be possible by the longer AOT. Describe your, or industry, experience associated with forced shutdown due to the current three-day AOT for CCPs. What is your expected frequency that you would use the proposed longer AOT?

Response:

Discussion of Averted Risk

In our original submittal, TU Electric noted that the time required to replace a failed centrifugal charging pump shaft would likely exceed the existing AOT, and therefore, without the extended AOT, there would be no alternative but to shut down the plant to repair a failed pump shaft. This constraint may put the plant at increased risk, compared to performing the repair at power. Having the extended AOT provides the option of performing the repair at power.

Averted risk is determined by comparing the relative risk of remaining at power to the transition and shutdown risk. A quantitative comparison of the relative risk involves defining the configurations and durations and calculating the respective core damage probabilities. A qualitative comparison of the relative risks should include consideration of changes to configurations and evolutions required to achieve them and how these are controlled at power and during shutdown to minimize risk. The approach taken for this response will be to use some quantitative information, where available, but primarily provide a qualitative response to the question. The approach demonstrates that the at-power risk level and duration are adequately controlled such that the risk is minimized, whereas in transitioning to shutdown, uncertainties and perturbations can introduce unknown risks.

Averted risk has been the subject of several industry studies which are relevant to the CPSES submittal. These studies have generally shown that the risk of remaining at power, even with significant equipment such as AFW pumps, Diesel Generators, and HPSI pumps out of service, is comparable and in most cases, less than the transition and shutdown risk. There is some uncertainty associated with these studies. This is primarily because the models for the shutdown modes required for calculating the transition risk and shutdown risk are not fully developed. However, the methodologies used in the studies appear to give conservative results and therefore, they are useful in this application. A discussion of these studies and other considerations is provided below.

Discussion:

When a piece of equipment has failed during power operation, the decision as to whether to repair the equipment at power or at shutdown involves an assessment or comparison of the relative risks. The risk of repairing the inoperable equipment at power is a function of, among other things, the specific equipment that is inoperable, the time it takes to perform the required repair, and the likelihood of challenges to the plant in the interval. The risks associated with shutting down are generally associated with potential plant upset during transition phases or mode changes, including upsets that would require functions normally provided by the inoperable equipment, coupled with other equipment failures.

Remaining at power minimizes perturbations to the plant whereas shutting down the plant introduces significant perturbation, may cause the likelihood of certain initiating events to increase, involves removal of automatic features and shifting equipment in and out of service, and puts larger demands on the operators. It is somewhat intuitive that such perturbations should be avoided, and as long as the risk level is not high, the at-power option is preferred.

As noted above, the at-power risk level depends on the specific equipment that is out of service. In general, a single train of equipment can be removed from service for maintenance while keeping the instantaneous risk at acceptably low levels. The studies mentioned above involve significant equipment being removed from service yet they show that as long as the duration of the at-power repair event is not excessive, the integrated risk, or core damage probability, remains low. The experience at CPSES is that the risk of evolutions is appropriately controlled, and as noted below in response to the Tier 3 questions, the on-line maintenance activities are controlled both for instantaneous core damage frequency and duration. In fact, the instantaneous CDF for a CCP out of service is 4.79 E-05 which is significantly less than the upper end of the CPSES-defined low risk threshold of 1E-04 and more than an order of magnitude less than medium risk threshold of 5E-04.

TU Electric also has in place significant controls during transition and shutdown to assure that the risk of evolutions is minimized. For this reason, it is reasonable to assume that the conclusions of the studies cited below are applicable to CPSES and the at-power risk level and duration is adequately controlled such that risk is minimized, whereas in transitioning to shutdown, uncertainties and perturbations introduce unknown risks.

Other Plant Studies:

To gain additional insight into the averted risk associated with the proposed extended CCP AOT, TU Electric reviewed the work of the Combustion Engineering Owners Group (CEOG), the Westinghouse Owners Group (WOG), and certain independent studies in the available literature that have evaluated these risks. This work is summarized in the sections below.

The first paper, Reference 1, provided a summary of a methodology and the results of its application at two CE plants. In one trial application of this methodology, a high pressure safety injection train was taken out of service. It was assumed that the time to transition to and from Mode 3 / Mode 4 was equivalent to the time interval for the repair at power. The results of this trial application indicate that the transition and shutdown risk is comparable to the risk of remaining at power while performing the necessary repairs.

A similar study by the CEOG for a joint application for Emergency Diesel Generator (EDG) AOT extension, Reference 2, provides similar insights. In this study, the averted risk of Diesel Generator repairs at power was evaluated. It was concluded that "....when the full scope of plant risk is considered, the risk incurred by extending the AOT for either corrective or preventive maintenance will be substantially offset by plant benefits associated with avoiding unnecessary plant transitions and/or reducing risks during plant shutdown operations, improved EDG reliability upon entering shutdown, and implementation of compensatory measures."

A third study , Reference 3, was done under the auspices of the U.S. Nuclear Regulatory Commission and involved an evaluation of averted risk, given known failures of the AFW systems of four different PWRs. The results show ".....that the risk of continuing power operation and plant shutdown both are substantial, but the latter is larger than the former over the usual repair time." In fact, the risk associated with the transition and shutdown option was substantially larger, e.g., by factors of ~4 to ~23 for the Westinghouse PWRs in the study.

TU Electric believes that the insights gained from these studies can be applied to this request for AOT extension. It is reasonable to expect similar results for CPSES CCP and thus similar conclusions. It our belief that the averted risk attendant to the extended AOT is likely to be substantial, especially in light of the study presented in Reference 3. Even if one assumes that the transition and shutdown risk is comparable to the risk of remaining at power, as indicated in Reference 1, the benefits associated with avoiding unnecessary plant transitions, with the uncertainties of human reliability and other factors, favors remaining at power. Thus, we believe that the extended AOT will allow TU Electric to avert significant risk should it become necessary to perform repairs of a centrifugal charging pump.

Reference 1: Gresham, Finnicum, Jaquith, Hackerott and Labrecquec; " A Methodology for Evaluation of Transition Risk", Proceedings of the International Topical Meeting on Probabilistic Safety Assessment - 96; September 29 - October 3, 1998; Park City, Utah.

Reference 2: Joint Applications Report for Emergency Diesel Generators AOT Extension, C-E Owners Group, May 1995

Reference 3: Mankamo, Kim, Yang, and Samanta; " Technical Specification Action Requirements for AFW System Failures: Method Development and Application to Four PWR Plants", Proceedings of the International Topical Meeting on Probabilistic Safety Assessment -96; September 29 - October 3, 1998; Park City, Utah.

Discussion of Industry Experience Associated with Forced Shutdown due to the Current three-day AOT for CCPs

Industry Experience:

There have been several instances in the industry of a forced or delayed outage due to centrifugal charging pump failure, in particular pump shaft related failures. The Systems and Equipment Engineering Subcommittee of the Westinghouse Owners Group conducted the Centrifugal Charging Pump Shaft Failure

Investigation program (References 4, 5) which addressed these failures. The program specifically addressed shaft failures of centrifugal charging/safety injection pumps originally manufactured by Pacific Pumps Division (now Ingersoll Dresser Pump Co.), namely the model 2-1/2" IL-RJ, an 11 stage horizontal centrifugal pump similar to those at CPSES. The study determined the following relevant information for failures:

- A total of 21 pump failures were studied. Of these, 16 involved shaft failures (three bent, five cracked and eight fractured shafts), and 5 involved seizure or severe degradation of the rotating element.
- There were nine emergency repairs for four-loop plants which required an average of 122 hours to complete, with a range of 72 to 192 hours. Table 1 below provides a listing of the failures, the associated repair times and an indication of whether or not the failure resulted in a forced outage.
- No three-loop plants reported a forced or delayed outage due to pump failure. All three-loop plants were designed with an installed spare charging pump, while only one four-loop plant (Millstone 3) had an installed spare pump.

TABLE 1: Westinghouse Four-Loop Plants with CCP Failures

#	Plant	Failure Date	Failure Type	Time to Repair (hr)	Forced Outage (Yes/No)
1	Catawba 2	Jul-88	Shaft rotated in full sine wave; loss of clearance; 80% crack	96	Yes
2	Catawba 1	Nov-89	Internal rub; loss of clearance; impellers 8-11 grooved	192	Yes
3	Sequoyah 1	Feb-91	280 degree crack under 11th impeller; evidence of debris	120	Yes
4	Callaway 1	Feb-92	Fracture at 1st locknut thread; no cavitation evidence	72	No
5	DC Cook 2	Jul-93	180 degree crack thru #9 keyway; 30 degree crack thru #8 key; #1 imp cavitation	85	No. AOT extension requested
6	Braidwood 1	Sep-93	No data available.	74.5	No. AOT extension requested
7	McGuire 1	Sep-93	Rotating element rub; seal and bearing failure; no cavitation	120	Yes
8	Vogtle 1	1988	Pump seized; cavitation damage	168	No. Refueling outage extended
9	Vogtle 1	1993	Pump seized; cavitation damage	168	No. Refueling outage extended

Reference 4: WCAP 14192, Centrifugal Charging Pump Shaft Failure Investigation.

Reference 5: NRC IN 94-76, Recent Failures of charging/Safety Injection Pump Shafts.

Discussion of Expected Frequency of Using Proposed AOT

CPSES has not experienced a forced shutdown of either unit for CCP failures as a result of the current 3-day AOT. There has been only one significant corrective maintenance activity on the four pumps. In that case, a pump assembly and speed increaser changeout was performed during the 6th refueling outage of Unit 1 (April 98) which took 128 hours to complete.

While it is possible that unavailability of the CVCS trains may increase given the longer AOT, the frequency of using the extended AOT is not expected to be high. The maintenance rule has performance criteria for unavailability of ECCS components and outage duration is appropriately controlled commensurate with these criteria. Furthermore, since the CPSES preventive maintenance schedule should minimize in-service failures. It is estimated that the frequency for performing corrective maintenance for such failures as a CCP pump shaft failure and/or its speed increaser to be twice on each train during the life of the unit.

3. **Provide the following information regarding PRA adequacy for the proposed application.**

   a. **We believe that your current internal event PRA is still the same as the original IPE in 1992. Explain how the IPE is still an adequate tool for the proposed application by discussing the changes made to the plant since the development of the IPE and their impact on risk.**

Response:

It is correct that the current CPSES internal events model is the same as the original IPE model in 1992 and the linked IPE model was used for this application. The IPE model has also been used for the CPSES Risk-informed IST application and for ranking SSCs for maintenance rule implementation. The CPSES IPE is based on the as-built , as-operated plant as of the freeze date of January 1992.

The CPSES IPE is adequate for this application even though there have been changes to the plant since the IPE was completed. This conclusion is based on several considerations which are developed and discussed further below.

First, the CPSES IPE shows a relatively flat CDF profile. That is, the CDF is fairly uniformly distributed by sequence type and initiating event. Thus, the CDF is not dominated by one or two systems, rather numerous systems, in particular the chemical and volume control system, are adequately represented in the profile. A significant change in plant design or operation would be necessary to significantly change this profile.

Second, though there have been changes or modifications to the plant, these modifications have generally made the affected systems more reliable, and in some cases more redundant or diverse. The CPSES IPE was essentially revalidated as being an adequate representation of the as-built , as-operated plant prior to submitting the IPEEE in 1995. The design modifications and procedures that could affect the IPE were reviewed at that time. It was determined that there were no significant impacts on the models that would make the results unconservative. At that time, one significant plant modification was in place, namely the installation of the new high temperature RCP seals.

Since that time, there have been a number of design modifications on both units. These modifications include the inverter modification which added a swing inverter, the instrument air system modification which installed higher capacity and more reliable compressors, the UPS HVAC system modification which added a diverse cooling system for the UPS rooms, and other minor modifications designed to achieve system/equipment reliability. The reactor protection system has been modified with installation of the so-called by-pass modification. This modification is a balance between unavailability and reliability that was evaluated by the NRC as part of a generic submittal. In addition to these modifications, certain model improvements have been identified that will be incorporated in the update.

Third, with regard to the as-operated plant, there have been two major revision to the ERGs since the completion of the IPE. The associated procedure changes do not significantly change the primary human actions to mitigate the consequences of accidents.

Fourth, the IPE data have been updated (though not yet incorporated into the model) to reflect CPSES plant-specific historical data. The data used in the original IPE were essentially generic for failure rates, corrective maintenance frequencies and durations, and initiating event frequencies. The update shows that, in most cases, failure rates have decreased. The data were plant specific for such things as tests, surveillance and preventive maintenance activities. Whereas these maintenance activities have changed somewhat since the freeze date, the maintenance rule monitoring of these systems shows a static or downward trend for some systems and a moderate increase for others. This would indicate that the changes in this area do not have a significant impact on the assumptions in the models. In summary, the revised data generally show an improvement in failure rates over the generic assumptions, and show that there are no outliers as regards assumed failure rates in the original IPE generic data.

Following the issuance of the CPSES IPE SER, the NRC conducted an on-site review of the IPE/PRA for the RI-IST program and has recently published its safety evaluation. That review was extensive and concluded that the CPSES IPE, even with its limitations, is adequate for RI-IST program. TU Electric believes that this conclusion also applies to this application. At the same time, the staff evaluations have identified some areas for subsequent review. TU Electric plans to address these areas as part of the PRA update process.

b. Describe any independent peer reviews performed on your PRA. Discuss your current effort to update your PRA. (Include discussion on both internal and external events).

Response:

To ensure a high-quality IPE and IPEEE, a[illegible]ovide quality control to the process, independent reviews of these activities were conducted. These reviews constitute the peer review of the CPSES IPE and IPEEE, as described below.

IPE Review Process

For the IPE process, two types of independent reviews were conducted. One was done internally by TU Electric staff or contractors, and the other was done externally by outside PRA experts. Both reviews were applied to the entire examination process except when it was not possible due to the availability of resources or required skills. In those few cases, as a minimum, each task was reviewed thoroughly by either an internal or external independent reviewer. Furthermore, a final independent review was performed after the IPE study was completed. A team of PRA experts was selected from the industry to independently review the entire IPE study and its supporting analyses. The review team spent one week at the TU Electric offices where documents, procedures and supporting calculations and analyses were available for use.

The results of all independent review activities performed by internal and external reviewers were well documented as part of the IPE documentation requirements. These independent peer review activities were reviewed as part of the NRC on-site review of the CPSES PRA for the Risk-informed IST project.

IPEEE Review Process

The IPEEE study was also independently reviewed by internal and external reviewers who had acknowledged expertise in their fields. The external reviews covered significant areas of the IPEEE study and were performed in most cases when the availabilities of internal resources and required in-house skills and expertise were limited.

In general, all portions of the IPEEE study such as fire and tornado evaluations were independently reviewed by one of the IPEEE team members who was not involved in the original analysis. In addition, when possible, another review was performed by the discipline engineers who were well familiar with the subject. The fire IPEEE study was reviewed by a fire protection engineer who was very familiar with the design basis issues pertinent to fire. This kind of review provided additional assurance that the models, plant configurations, related plant document and assumptions used in the IPEEE study were accurate and consistent with the current plant design and plant procedures. The high winds, external floods and other evaluations were reviewed in detail at the completion of those evaluations.

In addition, the CPSES project was the beneficiary of a wide range of expert review, both in the development of the methodology and its application at CPSES and in review of the results. As the methodology was developed, team review meetings, teleconferences, document reviews and field reviews were frequently held. The IPEEE project manager and the fire IPEEE project manager completed a detailed review of intermediate results which were reviewed with management, including a discussion of the analyses, preliminary results and walkdown findings. The fire IPEEE project manager performed a final review of the results and a detailed review of the final report. The study was independently reviewed again by fire protection and design engineers.

Current PRA Update Effort

TU Electric has determined that the PRA will be periodically updated to support the implementation of a Risk-informed IST program with updates occurring about every two refueling outages, including data updates, with emergent updates occurring when errors are discovered or when there are modifications to the systems that could significantly affect ranking.

Such an update is currently in progress. That update includes a review of each of the major areas of the Level I PRA, taking into consideration the NRC SER comments on the CPSES IPE and the NRC SER of the CPSES Risk-informed IST program. The areas involved in the Level II PRA will be reviewed to the extent necessary to support confirmation of the LERF model. The various areas of the PRA will then be updated as required to assure that the model has fidelity with the plant design and operation.

As discussed above, an initial data update was completed in 1996. That work may be supplemented in the current update project. In addition, as a first step in the update, a linked PRA model, based on the original IPE analysis, was developed in calendar year 1997.

An update of the IPEEE fire and tornado analyses is being considered for sometime after the completion of the internal events update.

c. **Describe the success criteria used for CCPs for different initiating events in your PRA and briefly explain the justifications.**

Response:

The chemical and volume control system functions and their corresponding success criteria are modeled in the both accident sequence analysis and the system fault tree models. The following describes the success criteria for both the system and sequence level analyses.

System Level Criteria

- Provide seal injection flow to each Reactor Coolant Pump (RCP). Success is defined as operation of at least one charging pump delivering 8 gpm to each RCP seal.
- Provide high head injection flow to the Reactor Coolant System (RCS) cold legs. Success is defined as operation of at least one CCP delivering flow to at least two RCS cold legs.
- Provide high head recirculation flow to the RCS cold legs. Success is defined as operation of at least one CCP delivering flow to at least two RCS cold legs.
- Provide emergency boration of the RCS. Success is defined as operation of at least one Boric Acid Transfer Pump delivering flow to the charging pump header with at least one charging pump delivering flow to the RCS via the normal charging flowpath.

Accident Sequence Level Criteria

Functional event trees and the corresponding top logic models were developed for each of the initiating event categories defined in the IPE. In addition, success criteria are defined for each of the branch points in the event trees are defined below for events requiring the use of the centrifugal charging pumps. The system level success criteria discussed above feeds into these event sequence branch points.

- Establish Bleed and Feed. Success is defined as one of two centrifugal charging pumps (CCP) or one of two safety injection pumps (SIP) taking suction from the RWST and discharging into the RCS, and one of two PORVs established prior to core uncovery. This branch point is used in the transient initiating event sequences.

- Establish Recirculation. Success is defined as one of two centrifugal charging pumps (CCP) or one of two safety injection pumps (SIP) taking suction from one of two residual heat removal pumps (RHRP) which are in turn taking suction from the containment sump and discharging into the RCS cold legs. This branch point is used in the transient, LOCA and SGTR initiating event sequences.

- Establish Safety Injection. Success is defined as one of two centrifugal charging pumps (CCP) or one of two safety injection pumps (SIP) taking suction from the RWST and injecting into the RCS. Depending on the break size, either accumulators and /or residual heat removal pump cold leg injection may be required. This branch point is used in the LOCA and SGTR initiating event sequences.

- Establish Feed and Bleed after SBLOCA. Success is defined as one of two centrifugal charging pumps (CCP) or one of two safety injection pumps (SIP) taking suction from the RWST and injecting into the RCS and one of two PORVs, all established prior to core uncovery. This branch point is used in the SBLOCA initiating event sequence.

- Seal LOCA due to loss of Cooling. Success is defined as component cooling water to the thermal barriers or seal injection from the chemical and volume control system is maintained. This branch point is used in the non-LOCA transient initiating event sequence.

- Long Term Shutdown. Success is defined as boration of the RCS using the chemical and volume control system taking suction from either the boric acid transfer system or from the RWST. This branch point is used in the ATWS initiating event sequence.

Success Criteria Basis

The system and sequence success criteria where the CCPs are required, as described above, are based on the design basis documents or where more realistic criteria were desirable, on supporting calculations performed as part of the IPE study. In particular, the success criteria for ECCS flow from CCPs or SIPs for the full spectrum of LOCA initiating events were evaluated in the supporting calculations. These calculations are primarily based on MAAP 3b thermal-hydraulic analyses. For Transient, ATWS, SGTR and RCP seal LOCA initiators, the success criteria are primarily based on design basis documents with timing evaluations done in supporting calculations.

It should be noted that the success criteria for ECCS, and thus for the CCPs, are being reviewed as part of the PRA update. This is in part to address the questions raised by the NRC staff in its review of the CPSES RI-IST program, in particular regarding success criteria for Feed and Bleed.

d. Describe your reliability and unavailability data for CCPs during last three years and compare with the data used in your PRA. Describe the result of any sensitivity study associated with the reliability and unavailability data.

Response:

Discussion of Unavailability of the CVCS Trains

The response to this request is based on the unavailability of the various CVCS trains as defined for maintenance rule implementation at CPSES. This provides a broader view of overall system performance. It should be noted that the actual average CCP unavailability is approximately 51% of the total unavailability of a given train. The unavailability for the CVCS System for the maintenance rule is set at 12.52 hours per month, based on two times the IPE assumption. The IPE assumes that a train's components are unavailable approximately 6.26 hours per month or 75 hours per year (75.17 hours). This is made up of the following: a CCP unavailable approximately 20 hours per year for test and maintenance, the room cooler unavailable 24 hours per year for corrective maintenance and other train-wise components unavailable for corrective maintenance approximately 31 hours per year.

The performance of the CVCS systems at CPSES is summarized below. In addition, a comparison of the performance to the IPE assumptions is included.

- Unit 1-Train A - Rolling Average Unavailability for the period 8/95-7/98 is 3.49 hours/ month. This is approximately 56% of the IPE assumption and 1/3 of the criteria level. The monthly unavailability hours during this period ranged from 0 to ~24 hours. The upper end of the range is ~ 1/3 of the current LCO time of 72 hours.

- Unit 1-Train B - Rolling Average Unavailability for the period 8/95-7/98 is 4.03 hours/ month. This is approximately 64% of the IPE assumption and <1/3 of the criteria level. The monthly unavailability hours during this period ranged from 0 to ~35 hours. The upper end of the range is <½ of the current LCO time of 72 hours.

- Unit 2-Train A - Rolling Average Unavailability for the period 8/95-7/98 is 3.01 hours/ month. This is approximately 48% of the IPE assumption and <1/4 of the criteria level. The monthly unavailability hours during this period ranged from 0 to ~46 hours. The upper end of the range is <2/3 of the current LCO time of 72 hours.

- Unit 2-Train B - Rolling Average Unavailability for period 8/95-7/98 is 3.55 hours/ month. This is approximately 57% of the IPE assumption and <1/3 of the criteria level. The monthly unavailability hours during this period ranged from 0 to ~34 hours. The upper end of the range is <½ of the current LCO time of 72 hours.

Discussion of Reliability of the CCPs

During the last three years (8/95-8/98), there has been only one functional failure of a centrifugal charging pump at CPSES. In that incident, operating CCP was declared inoperable because the CCP Main Gear Lube Oil pump was spinning freely and could not supply oil to the pump and its speed increaser bearings. During this period, approximately 48,960 operating hours have been accumulated and approximately 720 start demands accumulated for both units. This gives fails-to-run failure rates of ~ 2E-05 /hour and fails-to-start @ 0.0/ demand for the period. The CPSES PRA assumes fails-to-run @ 3.42E-05/hour and fails-to-start @3.29E-03/demand. Thus it can be seen that the performance of the CCPs for both units is better than that assumed in the PRA.

The reliability data reviewed includes the pumps and related components such as the associated lube oil system, speed increaser, and supply breaker.

Discussion of Sensitivity Studies Associated with the Reliability and Unavailability Data

The data used in the CPSES IPE is based on the PLG 500 Database. A plant specific data update was done for the period 1/91-12/94. That data shows that the performance of the CCPs is better than that assumed in the IPE. From this data it was found that the fails-during -operation failure mode is < ½ of the IPE and the fails-to-start failure mode is < 3/4 of the IPE. The data and the comparison to the IPE are shown in the table below.

Standby Pump Failure Data IPE (Includes CCPs)			
Failure Mode	**Mean**	**5th Percentile**	**95th Percentile**
Fails During Operation- IPE	3.42E-05/hr	2.68E-06/hr	9.32E-05/hr
Fails to Start- IPE	3.29E-03/demand	2.01E-04/demand	1.12E-02/demand
Plant Specific Data Update for CCPs (1/91-12/94)			
Fails During Operation- CCP Update	1.52E-05/hr	2.33E-06/hr	3.56E-05/hr
Fails to Start - CCP Update	2.41E-03/demand	2.12E-04/demand	7.39E-03/demand

It should also be noted that the performance of the CCPs since 12/94 continues to be excellent as indicated in the response to the question immediately above. Since the CDF for CPSES is based on the mean value, it is evident from the data that the core damage frequency would decrease when the updated data is applied.

e. **Describe any uncertainty/sensitivity analysis performed in support of the requested change.**

Response:

For this request, sensitivity studies consisted of examining the importance measures for the CVCS system for the various failure modes. These sensitivity studies show that the core damage frequency is relatively insensitive to changes in CCP unavailability or reliability, i.e., the relatively small RAW and FV importance measures. For example, the core damage frequency changes less than 1/10 of a percent for a doubling of the test and maintenance unavailability and less than ½ of a percent for a doubling of the demand failure rate. This is borné out in the response to RAI 2.b above. The doubling of the test and maintenance unavailability is in the range of expected increase for this request, namely a factor of 2 to 3.

It should also be noted that the sensitivity studies performed for the CPSES RI-IST submittal show that the risk ranking of important components is not overly sensitive to human reliability, common cause failure and recoveries. This is consistent with the conclusions provided above.

Tier 2: **Restriction on High Risk Configuration**

4. What are risk significant components/systems (according to your PRA) given a CCP is out of service? For those component/systems, describe what type of restrictions, or compensatory actions, e.g., TS and plant administrative procedures, would be in place to avoid/reduce potential risk-significant configurations.

Response:

Risk Significant Components Given a CCP is out of Service

The following provides a list of the risk significant components and /or systems given that a CCP is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high risk configuration, based upon their RAW value. These are not necessarily in ranked order.

- Electric Power - opposite train motive and control power
- Refueling Water Storage Tank - Tank and its associated discharge valves
- Service Water - opposite train
- Component Cooling Water- opposite train
- ECCS Injection/Recirculation flow path valves
- Emergency Diesel Generator - opposite train
- Electric Power - same train motive and control power
- Service Water - same train
- Component Cooling Water- same train
- CVCS - opposite train

Restriction on High Risk Configuration.

To avoid or reduce potential for risk-significant configurations from either emergent or planned work, CPSES has put in place a set of administrative guidelines that go beyond the limitations set forth in the plant Technical Specifications. These guidelines control configuration risk by assessing the risk impact of equipment out-of-service during all modes of operation to assure that the plant is always being operated within acceptable risk.

CPSES takes a conservative approach to on-line maintenance. The weekly schedules are train/channel based and prohibit the scheduling of opposite train activities without additional review, approvals and/or compensatory actions. The assessment process further minimizes risk by restricting the number and combination of systems/trains allowed to be simultaneously unavailable for scheduled work.

Unplanned or emergent work activities are factored into the plant's actual and projected condition. The present level of risk is evaluated. Based on the result of this evaluation decisions pertaining to what action, if any, are required to achieve an acceptable level of risk (component restoration or invoking compensatory measures). The unplanned or emergent work activities are also evaluated for their impact on planned activities and the affect the combinations will have on risk.

Tier 3: **Configuration Risk Management Program**

5. Describe your programs that provide reasonable assurance that the risk impact of out-of-service equipment is appropriately evaluated prior to and while performing any maintenance activity.

Response:

The CPSES programs that provide reasonable assurance that the risk impact of out-of-service equipment is appropriately evaluated prior to and while performing any maintenance activity are embodied in various site wide procedures. The upper tier procedure is Procedure No. STA-604, "Work Scheduling". This procedure prescribes the methods and assigns the responsibilities for scheduling of test and maintenance activities during at power operations and shutdown. This procedure requires that safety assessment processes be incorporated and implemented for all planned and emergent work activities. These review activities are discussed in more detail below.

Control of On-line Maintenance

The safety impact of equipment out of service for maintenance in Modes 1,2, 3 and 4 (i.e., on-line maintenance) is required to be evaluated as prescribed by Instruction No. WCI-203, "Weekly Surveillance / Work Scheduling."

- Instruction No. WCI-203, "Weekly Surveillance / Work Scheduling" prescribes the methods and assign the responsibilities for the development of the weekly surveillance / work schedule and the performance of the on-line maintenance safety assessment. This instruction applies to work activities for Modes 1, 2, 3 and 4. It requires a work schedule review either by the risk and reliability engineers or through the application of screening guidelines by work schedulers. The screening guidelines provide tables and a matrices for assessing the potential risk of removal of equipment from service. Based on these guidelines, work may either be implemented or deferred, or evaluated further by the risk and reliability engineers. Risk categories are used to define the acceptable risk levels and are the basis for the screening guidelines.

Basis for On-line Risk Category Definitions

The risk categories that were developed for the purpose of on-line maintenance risk assessments were defined using a methodology consistent with the overall public safety goal and the available industry guidelines, such as the draft EPRI PSA Applications Guide. They were also developed with the NRC safety goal for nuclear power plants in mind. That safety goal, 1E-04 per reactor year, is core damage frequency averaged over the entire year. The objective in assigning risk categories was to develop appropriate control measures to help assure that the goal is met.

For on-line maintenance risk assessments, the use of an instantaneous risk (i.e., using core damage frequency) was considered to be most appropriate. This instantaneous risk is defined as the estimated core damage frequency for a specific plant configuration at a point in time. The objective was thus to control the instantaneous risk level and the duration. This was accomplished by keeping the configuration-specific core damage probability (i.e., the instantaneous CDF multiplied by the time in the configuration) less than 1E-06.

To achieve the required configuration-specific core damage probability, a review of the 12 week rolling schedule was done to determine the acceptable range of instantaneous CDF for various configurations with the time in the configuration essentially controlled by technical specifications. Technical specifications action statements provided an adequate bounding estimate of time in the configuration. This approach provides reasonable assurance that the average annual core damage frequency of 1E-04 is not exceeded.

Based on the foregoing discussion, the risk categories were defined based on internal events CDF.

Risk Category 1:	High Risk
Risk Category 2:	High-Medium Risk
Risk Category 3:	Medium Risk
Risk Category 4:	Low Risk

In general, Risk Categories 1 and 2 are not allowed for scheduling of regular on-line maintenance activities. Risk Categories 3 and 4 are acceptable as long as the time in the configuration is controlled. The matrix provided in Instruction No. WCI-203 provides the work schedulers with the means of determining the category into which the work activity will fall.

<u>Control of Shutdown Risk</u>

Procedure No. STA-627, "Control of Planned Outages" prescribes the methods and assigns responsibilities for outage planning, scheduling, coordination and management to ensure that defense in depth of key safety functions is maintained. This procedure requires that an independent risk assessment of the outage schedule be performed and provides that the Outage Safety Function Guidelines should be used in this process.

The Outage Safety Function Guidelines provides information and guidelines relative to the conduct of outages at CPSES. These guidelines are based on management expectations, technical specifications, commitments, procedures, information gained from previous CPSES outages, industry experience, and other CPSES programs. These guidelines have also been incorporated into the ORAM software.

The Outage Risk Assessment and Management (ORAM) tool was developed as part of an EPRI project. It integrates the outage management guidelines and probabilistic shutdown safety assessment in a computer-based format and provides a means to evaluate outage schedules for risk. TU Electric uses ORAM at CPSES as part of its outage planning activities to help assure that the risk of operations during outages is well understood. During the planning phase, schedules of maintenance tasks are adjusted to project an acceptably low risk outage. As the outage progresses, the daily schedules are processed and maintenance tasks are scheduled accordingly. At the end of the outage, the ORAM tool is used to evaluate the effectiveness of the outage operations.

6. **The staff has determined that the TS Administrative Control section should describe the licensee's program for performing a contemporaneous assessment of the overall impact on safety of proposed plant configurations. In addition, the Bases for TS for which an extended AOT is granted should reference this program description. The program description, which is described in RG 1.177, should be incorporated into the TS Administrative Controls section.**

Response:

CPSES has evaluated recent Technical Specification changes regarding the Configuration Risk Management Program (CRMP) both submitted and approved by the NRC. TU Electric is currently processing a change to the Technical Specifications to include the below Configuration Risk Management Program (CRMP) into the administrative section of the Technical Specifications and referenced in the BASES section of the CCP Technical Specification. Completion of the reviews and approvals by the TU Electric Station Operations Review Committee (SORC) and Offsite Review Committee (ORC) is expected by the end of October with submittal of the supplement to License Amendment Request 96-006 to the NRC in early November.

Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1 at power internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Condition for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Condition for unplanned entry into the LCO Condition.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Condition.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.