June 22, 2001

MEMORANDUM TO: Robert A. Gramm, Chief, Section 1
Project Directorate IV
Division of Licensing Project Management

FROM: David H. Jaffe, Senior Project Manager, Section 1 ***/RA/***
Project Directorate IV
Division of Licensing Project Management

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 AND 2
RE: RECEIPT OF DRAFT INFORMATION

The U. S. Nuclear Regulatory Commission (NRC) staff has received the attached draft information from TXU Electric via E-Mails dated May 21, May 23, June 1, and June 11, 2001. This information was received from the licensee for the purpose of facilitating ongoing, unrelated, reviews and was not used by the NRC staff for any regulatory decisions. The purpose of this memorandum is to place the attachment in the Public Document Room.

Docket Nos. 50-445 and 50-446

Attachment: As stated

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OFFICE	PDIV-1/PM	PDIV-1/LA
NAME	DJaffe	DJohnson
DATE	6/21/01	6/21/01

OFFICIAL RECORD COPY

From: <jseawright@txu.com>
To: <dhj@nrc.gov>
Date: 6/11/01 10:41AM
Subject: RAI response

Dave,

Here is the draft response for the Calorimetric.

JDS

(See attached file: DRAFT RESPONSE TO CAL FOR LEFM.wpd)

EEIB1

> **.....Please submit a plant specific power calorimetric measurement uncertainty calculation, using an approved methodology, to establish the stated value of the uncertainty in thermal power measurement.....**

Response:

The CPSES-specific uncertainty analyses associated with the measurement of the core thermal power is based on the square root of the sum of the squares methodology summarized in "Westinghouse Setpoint Methodology for Protection Systems Comanche Peak Unit 1, Revision 1, " WCAP-12123, Revision 2, April, 1989. The Westinghouse statistical setpoint methodology was used for all setpoints presented in the plant Technical Specifications when CPSES Unit 1 was originally licensed. This methodology was licensed by TXU Electric from Westinghouse and applied to all RPS and ESFAS-related Technical Specification setpoints for the original licensing of CPSES Unit 2 and in all subsequent applications to either unit. References to this methodology may be found in the Bases to Technical Specification 3.3.1 and 3.3.2.

Similarly, the current power calorimetric uncertainty calculation is consistent with the 1990-vintage Westinghouse methods with which CPSES was originally licensed. Although specific input values have changed, the methodology has not been revised since the plant was initially licensed. This specific methodology was used to support the recent 1% power uprate to CPSES Unit 2.

In the current CPSES-specific application of this methodology to the core power measurement uncertainty when using the LEFM✓ as the source for the feedwater flow mass flow rate, the benefits attainable through the use of multiple channels are not pursued. In other words, the calculation is a single-loop uncertainty and overstates the actual uncertainty associated with the core power measurement. As noted in the "Response to NRC Request for Additional Information On License Amendment Request 98-010," (TXX-99105, April 23, 1999), from the

previous Unit 2 1% uprate documents, this approach is consistent with ASME PTC 19.1 - 1985, "Measurement Uncertainty."

The general methodology for determining the core power is summarized below:

$Q_{core} = Q_{ss} - NPHA$

where: Q_{core} = the core thermal power (BTU/hr)

Q_{ss} = the heat removal through the secondary side of the plant

$= W_f \cdot \{h_{stm}(P_{stm},x) - h_{fw}(P_{fw}, T_{fw})\} - W_{bldn} \cdot \{h_{stm} - h_{bldn}\}$

where W_f = Feedwater mass flow rate

h_{stm} = steam generator outlet steam enthalpy as a function of steam pressure and quality

h_{fw} = main feedwater enthalpy as a function of feedwater pressure and temperature

W_{bldn} = steam generator blow down mass flow rate

h_{bldn} = steam generator blowdown enthalpy

NPHA = the net pump heat adder, which is the sum of the heat addition added to the reactor coolant by the reactor coolant pumps less system heat losses, primarily attributed to the charging and letdown flows, less an allowance for the ambient heat loss attributed to conduction and convection from the RCS metal masses.

The uncertainty associated with the feedwater mass flow rate is extracted from the NRC-approved report by the LEFM✓ supplier, Caldon, Inc. ("Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM✓ System," ER-80P, Revision 0, March 1997).

The uncertainties associated with the remainder of the secondary-side heat removal calculation are determined by calculating the uncertainty associated with each process measurement (e.g., steam pressure) and then relating that uncertainty to an equivalent uncertainty associated with the secondary-side heat removal calculation through the use of sensitivity factors.

Effects of the Feedwater Flow Indication

The LEFM✓ system allows for a very precise determination of the feedwater mass flow rate. The LEFM✓ actually measures the fluid velocity. Based on precise measurements of the feedwater pipe diameter, a volumetric flow rate is digitally calculated. Given reasonably accurate feedwater pressure indications, the LEFM✓ digitally calculates a feedwater mass flow rate. As described in Reference 5, the

LEFM✓ can measure/calculate the mass flow rate to within ±0.48% of the nominal (or rated) feedwater flow. As may be observed in preceding equation, there is a direct, one-to-one relationship between the feedwater flow indication and the core thermal power indication.

Effects of Steam Generator Blowdown

To obtain the most "accurate" core thermal power measurement, steam generator blowdown should be isolated. However, recognizing that blowdown isolation is not always practical, an evaluation of the accuracy associated with the effects of blowdown on the secondary power uncertainty is appropriate.

When performing calorimetric measurements, the heat removal through the plant calorimetric measurement is calculated based on blowdown flow rate, pressure, and temperature. The "inlet" enthalpy for the blowdown heat balance is based on the feedwater pressure and temperature. If steam generator blowdown is not isolated, an explicit calculation of the blown heat removal rate is performed, based on the blowdown flow rate, pressure, and temperature. An uncertainty allowance of ±10% of the steam generator blowdown heat removal calculation is provided. Although typically operated at much lower flow rates, the maximum blowdown flow rate can be as high as approximately 310,000 lbm/hr. The exit temperature is approximately 500°F, and the pressure is approximately the feedwater pressure. Based on these conditions, the blowdown can remove approximately 6.26 Mwt (total, from all four steam generators). The nominal NSSS thermal power is 3458 Mwt plus the net RCP heat. Thus, blowdown accounts for a maximum of approximately 0.2% of the total heat removal through the secondary system. A ±10% uncertainty in the blowdown heat removal rate would affect the total NSSS calorimetric measurement by ±10% of 0.2%, or 0.02% RTP.

Effects of the Net Pump Heat Adder

The uncertainty associated with the net pump heat adder is derived by Westinghouse f rom the combination of primary system net heat losses and additions. The uncertainty allowance for the system heat losses (primarily attributed to charging and letdown flows) is ±10% of the measured value. An allowance of ±50% of the calculated value is provided for the ambient heat losses. The reactor coolant pump heat is known to a relatively high confidence level based on testing. Considering these parameters as one quantity, the arithmetically summed uncertainties (less than 2 MWt) are less than the value of ±0.085% RTP (used when RTP was defined to be 3411 MWt). This same conservative allowance will continue to be applied, even though Rated Thermal Power will be redefined as 3458 MWt.

For the remainder of the input parameters and indications to the core calorimetric measurement, standard SRSS methods are used to determine the uncertainty associated with a particular indication. Sensitivities of the core power to changes in the input parameters or indications are used to translate the uncertainty in the input to an equivalent uncertainty on the core calorimetric measurement. The sensitivities are summarized in Table 1.

The input parameters and indications actually used in the plant calorimetric measurement are feedwater pressure, feedwater temperature and steam pressure. A design allowance of 0.25% moisture for the steam moisture carryover input is used. Precision instrumentation, distinct from the main plant monitoring equipment, is used for this calorimetric measurement.

The basic components of the pressure indication uncertainty calculations (for both the main steam pressure and the feedwater pressure) are:

$$P_{unc} = \pm\{(SCA + SMTE + SD)^2 + STE^2 + SPE^2 + RCA^2\}^{1/2}$$

where (all units are % span):

SCA = Sensor calibration allowance
= ±0.60% span

SMTE = Sensor measurement and test equipment accuracy allowance
= ±0.60% span

SD = Sensor drift allowance between calibration intervals
= ±0.90% span

STE = Sensor temperature effect (an allowance for changes to the ambient temperature from calibration)
= ±0.25% span

SPE = Sensor pressure effect (an allowance, only required for differential pressure transmitters, for changes to ambient and process pressures from calibration)
= ±0.00% span

RCA = Rack calibration allowance (an allowance for the accuracy with which the plant computer reflects the signal from the transmitter) Because the plant computer, with its digital output, is used as the M&TE device in the calibration, only a very small value for RCA is required to address any uncertainties introduced by the indication. For example, the stated accuracy of the plant computer A/D and indication is less than ±0.05% span.
= ±0.15% span

Therefore,

$$P_{unc} = \pm\{(SCA + SMTE + SD)^2 + STE^2 + SPE^2 + RCA^2\}^{1/2}$$

$$= \pm\{(0.60 + 0.60 + 0.90)^2 + 0.25^2 + 0.0^2 + 0.15^2\}^{1/2}$$

$$= \pm 2.12\% \text{ span.}$$

These transmitters have a span of 500 psi; thus, the pressure uncertainty is 10.6 psi, rounded to 11 psi.

The feedwater temperature indication is calculated by the LEFM✓ system and has a stated accuracy of ±0.9°F.

The individual uncertainties associated with the precision calorimetric measurement are summarized in Table 1.

Table 1. Precision Calorimetric Uncertainties Using the LEFM✓

COMPONENT	INSTRUMENT ERROR	SENSITIVITY	POWER UNCERTAINTY
Feedwater Flow			
LEFM✓	±0.48%	1:1	±0.48% RTP
Steam Generator			
Blowdown	±10.0%	1:0.002	±0.02% RTP
Feedwater Enthalpy			
Temperature	±0.9°F	0.1430%RTP/°F	±0.129% RTP
Pressure	±11.0 psi	0.0001035%RTP/psi	±0.001% RTP
Steam Enthalpy			
Pressure	±11.0 psi	0.00491%RTP/psi	±0.054% RTP
Moisture	±0.25 %mst	0.85%RTP/%mst	±0.21% RTP
Net Pump Heat Addition			±0.085% RTP

The total power calorimetric uncertainty is:

$$\text{UNC-PWRCAL} = \pm\{(LEFM)^2 + (BLDN)^2 + (FWh_{temp})^2 + (FWh_{prs})^2 + (STMh_{prs})^2 + (STMh_{moist})^2 + (NPHA)^2\}^{1/2}$$

$$\text{UNC-PWRCAL} = \pm\{(0.48)^2 + (0.02)^2 + (0.129)^2 + (0.001))^2 + (0.054)^2 + (0.21)^2 + (0.085)^2\}^{1/2}$$

$$= \pm 0.55\% \text{ RTP}$$

This value is less than the value of ±0.61% RTP reported in the previously cited Caldon, Inc. Engineering Report (ER-80P).

EEIB1.

.... In addition, please provide a description of the programs and procedures that will control calibration of the LEFM system and the pressure and temperature instrumentation whose measurement uncertainties affect the plant power calorimetric uncertainties. In this description, please include the procedure for:

1. **Maintaining calibration,**
2. **Controlling software and hardware configuration,**
3. **Performing corrective actions,**
4. **Reporting deficiencies to the manufacturer, and**
5. **Receiving and addressing manufacturer deficiency reports.**

Response:

1. The LEFM✓ system contains self-diagnostic routines. Alarms annunciate the detection of any off-normal conditions (i.e., when monitored parameters fall outside acceptable ranges). In addition to the continuous self-diagnostics internally performed, the LEFM✓ system is periodically calibrated per the manufacturer's recommendations. This procedure also includes a calibration of the pressure transmitters which provide input to the LEFM and their associated A/D converters. A separate procedure is periodically performed to verify the adequacy of the calibration of all the transmitters and sensors, including the associated input to the plant computer, which are used as in the secondary calorimetric measurement.

2.-5. As described in FSAR Table 17A-1, the LEFM and its associated software are classified as non-1E equipment. Full QA requirements were not imposed for manufacture and/or installation; however, a specifically structured non-Appendix B QA program is applied at CPSES. The software and supporting hardware associated with the LEFM is controlled in accordance with the CPSES Nuclear Software Quality Assurance Program. This program includes measures to maintain the system in the validated configuration.

The CPSES Nuclear Software Quality Assurance Program includes provisions for reporting and resolving deficiencies as well as receipt and evaluation of condition reports received from the manufacturer. Non-conforming conditions are entered into the corrective action program where, among other activities, they are evaluated for 10CFR 21 reportability. This evaluation necessitates contact with the LEFM✓ system manufacturer. The manufacturer, Caldon, Inc., is also required, both contractually and in accordance with their Quality Assurance Plan, to report any non-conformance identified with the equipment or software to TXU.

From: <jseawright@txu.com>
To: <dhj@nrc.gov>
Date: 6/1/01 9:47AM
Subject: RAI

(See attached file: SPSB RAI r1.doc)

CC: "Don Woodlan" <dwoodla1@txu.com>

SPSB1. What design bases parameters, assumptions or methodologies were changed in the radiological design basis accident analyses because of the proposed changes? If there are many changes, it would be helpful to compare and contrast them in a table. Also, please provide justification for any changes.

SPSB2 Please describe how the source terms utilized for your dose analyses were generated. Provide the methodology, codes, and databases utilized.

SPSB3. Please provide the offsite and control room dose results from your accident analyses.

DRAFT RESPONSE

In response to SPSB1, SPSB2, and SPSB3 above, CPSES has not changed any of the licensed design bases to the control room and offsite dose consequences presented in the FSAR. Cycle specific assessments are performed as part of each reload analyses to confirm that the radiological analyses presented in the FSAR remains bounding.

The radiological dose consequences reported in FSAR Chapter 15 are based upon the computer analysis tools used for dose consequence calculations listed in FSAR Appendix 15B and a reactor power of 3565 MWth (104.5% of 3411 MWth). Neither the assumed reactor power of 3565 MWth, nor the licensing basis methodologies have been changed in support of the proposed amendment to increase the Rated Thermal Power for Units 1 and 2 to 3458 MWth (1.4% and 0.4% increases, respectively).

The radiological dose consequences are based on a fission product inventory derived from an assumed reactor power of 3565 MWth (104.5% of original licensed power level) and a standard three region 12 month fuel cycle at equilibrium. (i.e., a total core mass loading of 89.05 MTU, core average burnup of 24,018 MWD/MTU, and a 12 month fuel cycle with 3 fuel burnup regions of 300, 600, and 900 EFPD). The radiological dose consequences derived from the above fission product inventory has continued to remain bounding through the increase in fuel enrichments and cycle lengths as provided for in amendments 17/3 and 27/13 to the Technical Specifications because of the significant margin provided by the assumed power level of 3565 MWth. The radiological dose consequences presented in the FSAR continue to remain bounding upon implementation of the proposed amendment to increase the Rated Thermal Power to 3458 MWth for Units 1 and 2. This conclusions has also been confirmed to remain valid when an additional allowance

of +0.6% has been included to address the power calorimetric uncertainty; (i.e. the assessments for this submittal were performed at 3479 MWth).

The cycle specific fission product inventories submitted in the proposed amendment provide an example, from a previous cycle, as to how the overall effects of the fission product inventories are assessed to assure that the radiological dose consequences remain valid for each cycle. The current cycles for Unit 1 and Unit 2 have been assessed at 3479 MWth, and, as before, it has been determined that the radiological dose consequences presented in FSAR Chapter 15 continue to remain valid.

From: "Michael Riggs" <mriggs1@txu.com>
To: <dhj@nrc.gov>
Date: 5/23/01 3:08PM
Subject: Preliminary Response to RAI re: LAR 01-06

Mr. Jaffe,

Attached is a WordPerfect file with responses to questions on CPSES License Amendment Request (LAR) 01-06 as discussed on May 9, 2001.

Mike Riggs

(See attached file: Rai.wpd)

CC: <skarpyak@txu.com>, "Dan Tirsun" <dtirsun1@txu.com>, "Don Woodlan" <dwoodla1@txu.com>

SUBJECT: Preliminary Response to Request For Additional Information Regarding Comanche Peak Proposed Technical Specification Change as Submitted in License Amendment Request (LAR) 01-06

REF: Conference Call on May 9, 2001 between NRC's D. H. Jaffe and Millard Wohl, and CPSES' Steve Karpyak, Dan Tirsun, and Michael Riggs

The following questions were asked by Millard Wohl / Dave Jaffe regarding the CPSES DG AOT submittal (LAR 01-06) : [Questions have been paraphrased based on participant notes.]

1. Provide some additional bases for excluding externals from the quantitative assessment. These bases can be qualitative.

Response: CPSES has prepared an engineering report in support of the subject submittal. The following excerpts from this report provide the basis for excluding external events.

<u>External Events</u>

Fires

The IPEEE fire analysis results for Comanche Peak were not combined with the internal events PSA results. The risk metrics calculated for this submittal, therefore do not include contributions from internal fires. However, the IPEEE fire risk assessment at Comanche Peak did not identify any vulnerabilities associated with diesel generators.

In order for fires to affect the risk metrics evaluated for the EDG AOT submittal, they would have to either a) cause a Loss of Offsite Power through cable damage, b) cause a LOSP and fail a EDG at the same time (while not failing the electrical bus).

Due to the actual installed cable routing and separation criteria, a significant fire that affects multiple compartments and multiple trains of equipment would be required to initiate a LOSP. The probability of occurrence of a fire of this magnitude is at least two orders of magnitude below the frequency of a random LOSP.

The change in risk (as determined by CDF and LERF) due to the increased Completion Time is dominated by accident sequences involving independent EDG maintenance unavailabilities. The proposed changes to the EDG Completion Time has a negligible effect, if any, on fire risk. A similar argument applies to the start-up transformers.

Tornadoes

The inclusion of LOSP due to tornadoes can not increase LOSP-induced CDF by more than 10% even if conservative assumptions are used. The CDF calculations still support the extension of EDG AOT, although it is necessary to argue the differential risk by moving the EDG overhaul from shutdown to Mode 1.

The base case (internal events excluding fires and floods) CDF for the updated Comanche Peak PSA is 2.0E-5/yr while in Mode 1. The PSA includes an initiator for LOSP. The IE frequency and recovery probabilities for LOSP are derived from generic and plant specific experience and as such include the effect of tornado-induced LOSP. The IPEEE (completed in 1995) addresses CDF specifically from tornadoes. The probability of a direct hit was 5E-4/ year. The IPEEE calculates CDF due to tornadoes as 3E-6. However, the recent update to the PRA changed the data for SBO-related events. Rather than revise the IPEEE, a scoping assessment of tornadoes has been performed.

It is assumed that occurrence of a tornado is 5E-4/yr, which will guarantee a LOSP and eliminate the possibility of recovery for 24 hours. The scoping assessment is made by using the event importance values for the base case PSA. The mission time is 24 hours. This coincides with the mission time for the diesel generators.

In the updated PSA, the base case contribution of LOSP to CDF is 1.64E-5/yr. Virtually all (98%) of this CDF is due to station blackout (i.e., failure of both EDGs). LOSP with one EDG operable is a minimal contributor. If there is no recovery of OSP, the CDF is raised by 7.14E-5/yr. to 7.52E-5/yr.

If a tornado initiating event frequency of 5E-4/yr. is assumed, (guaranteed LOSP and no recovery for 24 hours), the CDF from tornadoes is 9.04E-7/yr. If the EDG overhaul is allowed during Mode 1, the increase in EDG unavailability will increase the CDF by 1.35E-7.

Based on the above scoping assessment, specifically including tornado as an IE increases the base case CDF by 5%. If the 14-day AOT is allowed at power, the CDF is further increased by 1.35E-7/yr., an insignificant increase.

If the risk trade off between shutdown and power operation is considered, the consideration of tornadoes has no effect on the EDG AOT extension. A similar argument applies to the start-up transformers. The conditional probability of core damage for the 24-hour station blackout is 1.0 for all operating modes, with possibly the exception of Mode 6 with high water level. So the ICCDP for EDG overhaul is the same regardless if it occurs in Mode 5 or Mode 1, and thus the

ICCDP as calculated by RG 1.177 is not an *increase*, but rather a moving of core damage probability from Mode 5 to Mode 1.

2. Was a corrective maintenance case run for the Diesel Generators with a common cause beta included? Did it show the ratio of CM to PM?

Response: The corrective maintenance with common cause beta has been run to support some information for the WOG submittal. We will extract that calculation and discussion from the report and use it here.

As part of CPSES participation in the WOG RI-DG AOT submittal, additional analyses were required to support this effort. To evaluate the impact of diesel generator major maintenance activities, the following steps were performed using the Westinghouse Owner's Group guidance presented in "General Process for Safety Impact of Changes to Technical Specification Allowed Outage Times", Westinghouse Owner's Group, March 10,1999. The following case studies were performed.

Train 'A' EDG Out of Service for Corrective Maintenance.

The Safety Monitor™ Administrator Module was used to modify the values of the following basic events:

- **EPCCFDGD12 0.00E-0**
- **EPCCFDG012 0.00E-0**
- **EPBDGGEE02NN 3.12E-2**
- **EPBDGGEE02FN 4.01E-2**

The change in the basic events list above reflect the WOG methodology in which the failure rates associated with the remaining operable DG are increased by the Beta CCF factor and the original model CCF events are set to 0.0. This is based on the WOG methodology when one EDG is assumed out of service for corrective maintenance.

The following configuration changes along with the basic event probability modifications define the input into the Safety Monitor™ (Case 300).

- **Train 'A' EDG removed from service**
- **Alignments were change to show Train 'B' equipment running and Train 'A' equipment in standby.**

Train 'B' EDG Out of Service for Corrective Maintenance.

The Safety Monitor Administrator™ Module was used to modify the values of the following basic events:

- **EPCCFDGD12 0.00E-0**
- **EPCCFDG012 0.00E-0**
- **EPADGGEE02NN 3.12E-2**
- **EPADGGEE02FN 4.01E-2**

The change in the basic events list above reflect the WOG methodology in which the failure rates associated with the remaining operable DG are increased by the Beta CCF factor and the original model CCF events are set to 0.0. This is based on the WOG methodology when one EDG is assumed out of service for corrective maintenance.

The following configuration changes along with the basic event probability modifications define the input into the Safety Monitor™ (Case 301).

- **Train 'B' EDG removed from service**
- **Alignments were change to show Train 'A' equipment running and Train 'B' equipment in standby.**

.

TABLE 1 Summary of Corrective Maintenance Cases				
300	A EDG OOS for corrective maintenance	CDF= 1.28E-4 per year (1)	LERF= 1.67E-5 per year (1)	Adjusts common cause failure rates to 0 and increases the failure probability for the B EDG by the common cause Beta factor.
301	B EDG OOS for corrective maintenance	CDF= 1.27E-4 per year (1)	LERF= 1.67E-5 per year (1)	Adjusts common cause failure rates to 0 and increases the failure probability for the A EDG by the common cause Beta factor.

Note 1: Indicates average Test and Maintenance on the associated train for equipment out of service in addition to the EDG.

These results show that the ratio of CDF CM to CDF PM is 1.28/1.12 = ~ 1.14

The following table shows the values, methodology and results of calculations for the various preventive and corrective maintenance cases.

Comanche Peak 14 Day AOT – CDF Calculations for Corrective Maintenance Common Cause Failure Cases

Required Information	Parameter
DG fail to start failure probability	8.418E-03
DG fail to run failure probability	3.356E-02
DG required mission (run) time in hours	23
DG common cause failure model	MGL Methodology
DG fail to start common cause failure probability (all DGs)	2.624E-4 Beta of 3.12E-2
DG fail to run common cause failure probability (all DGs)	1.402E-3 Beta of 4.01E-2
CDF (current AOT)	1.17E-5
CDF (proposed AOT)	2.55E-5
CDF increase	1.38E-5
CCDF (with one DG out of service due to test or scheduled maintenance activity)	1.12E-4[1] Case 102C
CCDF (with one DG out of service due to corrective/repair maintenance activity)	1.28E-4[1] Case 301
ICCDP (with one DG out of service due to test or scheduled maintenance activity)	3.74E-6
ICCDP (with one DG out of service due to corrective/repair maintenance activity)	4.28E-6

[1] Indicates average T&M on the associated train for equipment out of service in addition to the EDG

3. Shutdown risk is dominated by the mid-loop. It appears that the DG AOT is scheduled during the mid-loop. Please confirm that. Discuss how the DG outage is timed/scheduled with respect to mid-loop, in particular in the early stages of the outage.

Response: CPSES does start the DG outage as soon as TS allow operation with only one DG, at start of mode 5. That means that one DG is unavailable during the early mid-loop and accounts for the risk level. Depending on the length of the DG outage, it is possible that the other DG could be out during the late mid-loop. This is normally what is scheduled and done during outages at CPSES.

4. Is there an editorial problem on the wording of the lead-in to the bulleted list on Page 33, or was something left out?

Response: This is editorial. We will correct the lead-in sentence to read " Updated the PRA model . . ."

5. Do you use Safety Monitor for on-line and ORAM for shutdown?

Response: Yes, Safety Monitor is used for modes 1 and 2 on-line and ORAM is used for shutdown modes 5 and 6. The Safety Monitor is also capable of analyzing transition modes (modes 3-4) and shutdown (modes 5 and 6).

6. Does CPSES use Maintenance Rule a(4) and Configuration Risk Monitoring Program (CRMP)?

Response: Yes, CPSES currently has both a(4) and CRMP processes for controlling maintenance configuration risk. These are considered redundant but CPSES has not requested in this LAR that CRMP be deleted from technical specifications.

7. How is Spent Fuel Pool enveloped in this analysis? Does the CPSES Safety Monitor model SFP releases or just cooling?

Response: The Safety Monitor models SFP cooling, however, it does not model SFP releases. The Safety Monitor model calculates both time to boil and core damage. Both metrics are calculated based on time after shutdown and assuming that once fuel transfer begins, the pool's decay heat load is based on full core off-load with existing fuel accounted for in the decay heat calculation.

8. Discuss the organizations and some of the names of individuals who participated in the reviews of the CPSES PRA, including the IPE.

Response: Provide a listing of the companies and the individuals who reviewed the CPSES IPE/PRA and provide a listing of companies and individual who assisted in the PRA update.

The following organizations and individuals provided independent review of the initial PRA:

J. Gaertner, ERIN; D. Wakefield, PLG; B. Najafi, B. Putney, R. Anoba, Z. Mendoza, SAIC; A. Spurgeon, APG; A. Torri, Risk and Safety Engineering; J. Zamani; F. Hubbard, FRH, Inc.

The following organizations and individuals (principals) provided review and individual expertise in support of updates of the PRA:

D. Jones, Scientech; J. Julius, Scientech; R. Anoba, Anoba Consulting; C. Cragg, DS&S; S. Rao, J.C. Lin, PLG.

From: <jseawright@txu.com>
To: <dhj@nrc.gov>
Date: 5/21/01 10:11AM
Subject: RAI

Dave,

Don asked me to email this proposed response to you.

JDS

(See attached file: SPSB RAI.doc)

SPSB1. What design bases parameters, assumptions or methodologies were changed in the radiological design basis accident analyses because of the proposed changes? If there are many changes, it would be helpful to compare and contrast them in a table. Also, please provide justification for any changes.

SPSB2 Please describe how the source terms utilized for your dose analyses were generated. Provide the methodology, codes, and databases utilized.

SPSB3. Please provide the offsite and control room dose results from your accident analyses.

DRAFT INITIAL RESPONSE (05/15/2001)

In response to SPSB1, SPSB2, and SPSB3 above, CPSES has not changed any of the licensed design bases to the control room and offsite dose consequences presented in the FSAR. Cycle specific assessments are performed as part of each reload analyses to confirm that the radiological analyses presented in the FSAR remains bounding.

DRAFT FOLLOW UP ON BASED ON 5/17/2001 TELECON WITH DAVE JAFFE AND MARK BLUMEBURG:
The licensing basis dose consequences reported in the FSAR are based upon the computer analysis tools used for dose consequence calculations, which are listed in the FSAR, and a reactor power of 3565 MWth (104.5% of 3411 MWth) likewise listed in the FSAR. Neither the reactor power, of 3565 MWth, nor the licensing basis methodologies have been changed in support of the proposed amendment to increase Units 1 and 2 reactor power to 3458 MWth (1.4% and 0.4% increases).

The dose consequences that provides the license basis, as reported in the FSAR, are based on a fission product inventory derived from an assumed reactor power of 3565 MWth (104.5% of original licensed power level) and a standard three region 12 month fuel cycle at equilibrium. (i.e. a total core mass loading of 89.05 MTU, Core Average Burnup of 24,018 MWD/MTU, and12 month fuel cycle with 3 fuel burnup regions of 300, 600, and 900 EFPD.) The FSAR license basis dose consequences derived from the above fission product inventory has continued to remain bounding through the increase in fuel enrichments and cycle lengths as provided for in amendments 17/3 and 27/13 of the Technical Specifications because of the significant margin provided by the assumed power level of 3565 MWth provided in the license bases. The FSAR license bases dose consequences will continue to remain bounding upon implementation of the proposed amendment to increase reactor thermal power to 3458 MWth for Units 1 and 2.

The FSAR license bases values for dose consequences remain bounding, by determining that the cycle specific fission product inventory is overall less severe and that the licensing basis (i.e. dose consequences) remains unchanged from that already reported in the FSAR.

Cycle specific fission products that were submitted in the proposed amendment provide an example as to how the overall effects of the fission product inventories assessed to assure that the FSAR license basis dose consequences remain bounded on a cycle specific basis.