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CPSES-200300262
Log # TXX-03024

March 5, 2003

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

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
UNIT 1 - DOCKET NO. 50-445
SUPPLEMENTAL INFORMATION FOR CONSIDERATION
DURING SIGNIFICANCE DETERMINATION PROCESS REVIEW
OF APPARENT VIOLATION 50-445/0209-01

REF: NRC Inspection Report No. 50-445/02-09; dated 9 January, 2003

Gentlemen:

TXU Generation Company LP (TXU Energy) has reviewed the referenced NRC Inspection Report and herein makes available additional information for consideration by the NRC Staff during their Significance Determination Process (SDP) Phase 3 analysis of the Apparent Violation (APV 50-445/0209-01) contained within that report.

Enclosure 1 to this letter contains a brief description and background of TXU Energy's Probabilistic Risk Assessment (PRA) model at CPSES. This enclosure provides information on the origin, structure, maintenance, updates, and prior approved uses of the CPSES PRA model.

Enclosure 2 to this letter contains TXU Energy's SDP Phase 3 PRA of the subject condition. TXU Energy believes this evaluation to be a comprehensive PRA Level I and II analysis, in that it addresses both Core Damage Frequency/Core Damage Probability (CDF/CDP) and Large Early Release Frequency/Large Early Release Probability (LERF/LERP) considerations for both Direct Steam Generator Tube Rupture (SGTR) events and for Induced SGTR events.

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Enclosure 3 to this letter contains an assessment of the flaw characteristics that formed the basis for the tube failure probabilities used in Enclosure 2.

TXU Energy believes NUREG-1765[1], as the latest guidance document published by NRC staff for a proposed SDP based on change in CDF (ΔCDF) and change in LERF (ΔLERF), is the appropriate method to perform the Phase 3 SDP of this finding. As stated in the Foreword to NUREG-1765;

> "By using the information in this report, NRC staff, including resident inspectors, will be more effective and efficient by focusing resources on risk important inspection findings. This also supports the agency's performance goal to reduce unnecessary burden on stakeholders by de-emphasizing activities in areas of low risk importance. A draft version of this report was incorporated into Inspection Manual Chapter 0609 as Appendix H. We have endeavored to incorporate the comments from the regions and NRR into this final version, **which should be used in lieu of the draft version in Appendix H.**" *(emphasis added)*

Based on the results of the scenarios as presented in Enclosure 2 and summarized in the table below, the potential risk increase associated with the leaking tube, given in values of Incremental Conditional Core Damage Probability (ICCDP) and Incremental Large Early Release Probability (ICLERP), is found to be insignificant.

CPSES PRA Analysis Section	ICCDP	ICLERP
4.1.1; Potential Increase in Spontaneous SGTR Frequency	1.50E-08	1.58E-08
4.2.1; Potential Increase in SGTR Induced by MSLB	2.95E-09	2.95E-09
4.3.1; Potential Increase in Induced SGTR Frequency	N/A	3.69E-08
Total	1.79E-08	5.57E-08

For SDP Phase 3 considerations, the ICCDP and ICLERP were compared to the guidance provided by the NRC in NUREG-1765[1] for ΔCDF and ΔLERF. Since the calculated values of our Phase 3 analysis fall below the minimum frequency threshold of 10^{-7}, we believe that the condition captured by the apparent violation should be most appropriately characterized as a GREEN finding.

1 NUREG-1765; "Basis Document for Large Early Release Frequency (LERF) Significance Determination Process (SDP); Inspection Finding that May Affect LERF" December 2000.

TXU Energy understands that the behavior of steam generator tubes under severe accident conditions is the subject of current NRC research programs. These activities, initiated by the NRC under both the Risk Informed Regulation Implementation Plan (RIRIP) and the Steam Generator Action Plan (SGAP), will provide added insights into the performance of steam generator tubes under severe accident conditions well beyond those presently incorporated in the licensing basis of most plants, including CPSES. However, these research and implementation plans have not been completed, and any preliminary insights they provide have not been fully reviewed, validated, or approved by the Commission for incorporation into current regulatory policy.

TXU Energy believes any initiative by the NRC Staff to go beyond the current guidance of NUREG-1765 and to attempt to specifically calculate the risk of this apparent violation, using the incomplete analysis of tube behavior under severe accident conditions, is unwarranted and would be a premature use of a regulatory framework that is still under development.

In addition, TXU Energy believes that NRC actions designed to address accident scenarios beyond a plant's current licensing or design basis should be considered a backfit and would be more appropriately implemented by means of NRC generic communications, or rulemaking if the design basis of any plants are believed to be inadequate.

To promote consistency in the determination of risk presented by this finding, the manner in which this violation is characterized should be compared to any available recent inspection findings of similar circumstances. In NRC Inspection Report 50-270/02-05, a plant in NRC Region II was recently discovered to have failed to detect a flawed steam generator tube in the prior refueling outage and the tube was not removed from service. While the tube did pass the accident-induced leakage and operational leakage performance criterion of NEI 97-06[2], it failed to meet the structural integrity performance criterion of NEI 97-06 during in-situ testing. In the Inspection Report, this violation was characterized by Region II inspectors as a GREEN finding with no detailed analysis of the risk.

2 NEI 97-06; "Steam Generator Program Guidelines," Revision 1.

In summary, while operational leakage never exceeded approved Technical Specification limits, TXU Energy did take conservative action to shutdown the plant and commence the scheduled outage period early rather than continue operation with a leakrate that was well within our operational basis. Additionally, TXU Energy believes our SDP Phase 3 PRA is comprehensive and adequately analyzes all relevant accident scenarios within our design basis. Based upon the results of this SDP Phase 3 PRA, we conclude that the condition captured by the apparent violation would be most appropriately characterized as a GREEN finding due to the minimal increase in risk presented.

If you have any questions concerning this issue, please contact Roger Walker at (254) 897-8233.

This communication contains no new licensing basis commitments regarding CPSES Units 1 and 2.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

C. L. Terry
Senior Vice President and Principal Nuclear Officer

By: Roger D. Walker
Roger D. Walker
Regulatory Affairs Manager

RJK/rk
Enclosures

c - E. W. Merschoff, Region IV
W. D. Johnson, Region IV
D. H. Jaffe, NRR
Resident Inspectors, CPSES

ENCLOSURE 1 to TXX-03024

Comanche Peak Steam Electric Station (CPSES) Probabilistic Risk Assessment (PRA) Background and History

Comanche Peak Steam Electric Station (CPSES) Probabilistic Risk Assessment (PRA) Background and History

Background

Through the years, CPSES has invested significant time and resources in the development, improvement and application of Probabilistic Risk Assessment (PRA) models. Level I and Level II analyses have been completed to assess the frequency of significant core damage and containment performance for CPSES. These analyses were submitted as the CPSES Individual Plant Examination (IPE) to the NRC in August and October 1992, respectively. There are no plans to complete a Level III analysis for CPSES at this time.

The Level I model results in a significant number of core damage sequences. To simplify the interface between the Level I model and the Level II model, core damage bins are defined. The core damage bins allow grouping of sequences that have similar accident progression. A set of parameters is identified that can be used to define unique accident sequences. The timing of vessel failure is an example of one of the parameters used to bin accident sequences. A containment event tree is used to evaluate the response of the containment structure and systems following a core damage event. The basic premise of the Level II PRA is that only Large Early Releases significantly affect the health and safety of the public. Generally, Large Early Release will comprise:

- Containment bypass core damage sequences (i.e., Steam Generator Tube Rupture and ISLOCA), and
- Core damage sequences with unscrubbed containment failure pathway of sufficient size to release the contents of containment (i.e., one volume change) within one hour, which occurs before or within four hours of vessel breach.

CPSES emphasizes the importance of maintaining the quality of the PRA model. The model has been updated recently to reflect current plant configuration. The following discussions describe:

- Model Structure,
- Model Development and Review,
- Model Update History,
- Current PRA model, and
- Risk Informed In-Service Testing NRC Submittal.

Model Structure

The CPSES PRA Level I model consists of three basic components: event trees, fault trees, and failure data. The actual logical structure of the PRA model is created in event trees and fault trees. The development of a PRA model is based on failures as opposed to successes.

Event Trees

Event trees are used to create the sequence of events that must occur to result in a core damage or containment failure event. All of these event trees were translated into a top logic fault tree model which has been linked with the various front-line and support system models to allow for more rapid quantification of the CPSES PRA. Internal initiating events, including internal flooding events and ISLOCA events, are evaluated using the combined fault tree model. Although the internal flooding events use the same model, their results are maintained separate from the base PRA model. This is done to facilitate using the PRA model for its various applications, including on-line risk monitoring and maintenance rule evaluations.

So that the event trees could be used as the basis for processing the probabilistic and frequency information, success and failure definitions were defined. These success criteria were determined from past safety analyses or from the results of specific analyses performed to support the PRA. Timing studies using thermal-hydraulic computer models were performed to determine estimated accident response times and to confirm the success criteria. In addition, discussions were held with operations personnel to verify the validity of the proposed events. When the event tree was complete, the end point for each possible event tree sequence was defined as core damage, non-core damage, or a transfer to another event tree, and the resulting core damage bin was identified.

Fault Trees

Fault trees are used to model functions specified in the event trees, and typically represent the logic associated with failure of a system or combinations of systems.

Data

There are four basic data types used in the CPSES PRA model:
1. component failure data (independent and common cause)
2. initiating event data
3. component test and maintenance unavailability data
4. human reliability data

These data can be determined using plant-specific information and/or generic industry failure data from various industry publications, such as other PRAs, contractor data summary reports (e.g. PLG-500), NUREGs and IEEE-500. Plant specific data is preferred over generic data because it more closely reflects the plant's design and operating and maintenance practices.

Model Development and Review

Original CPSES IPE Development

One of the main objectives during the original IPE development was to develop a model that would be able to be used in the future to help enhance plant safety through risk-based applications. With this objective in mind, the IPE elements were developed in detail and integrated in a manner sufficient to satisfy both the NRC Generic Letter 88-20 requirements and support future plant applications.

The CPSES IPE study was performed by developing large fault trees and small event trees. The large fault trees were then linked together according to the event tree logics for quantifying accident sequences. The major elements of the IPE study were developed and reviewed in a manner consistent with and in excess of the good practices of the time. In general, it is believed that the CPSES IPE meets or exceeds the quality standards subsequently suggested by the EPRI PRA Applications Guide.

IPE Review Process

To ensure a high-quality IPE and to provide quality control to the IPE Process, two types of independent reviews were conducted. One was done internally by CPSES staff, and the other was done externally by outside PRA experts. In general, 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 CPSES 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. Reviews associated with the IPE process confirmed the PRA model represented the as-built, as operated plant.

Subsequent Reviews

Since the IPE review, the CPSES PRA has been extensively reviewed by both in-house PRA staff and outside PRA experts. NRC and its PRA experts as part of the RI-IST Pilot Plant submittal reviewed the CPSES PRA in detail.

The CPSES PRA model has been subject to periodic review in conjunction with updates incorporating plant procedure revisions, plant modifications and plant specific operational data. Further review occurred when the model was reviewed under the Westinghouse Owner's Group (WOG) Peer Review Program. The results of this latter review have been evaluated for future updates to the model with significant comments incorporated. Based on this effort, the WOG review concluded; "The Comanche Peak PRA can be effectively used to support applications involving risk significance determination supported by deterministic analysis."

Model Update History

The PRA level 1 model has been updated several times since the original IPE submittal. The current PRA model includes modeling enhancements that were identified as part of an overall model update, and insights gained when using the PRA model in support of several risk-based initiatives. The first major update to the PRA was performed to support a linked fault tree model. By revising the top logic (event tree/fault tree interface) to support a linked fault tree model, the effort required to requantify the PRA was reduced substantially.

A second major revision to the PRA model occurred when the model was modified to allow it to be used by the Safety Monitor software for on-line risk monitoring. In order to support the development of a Safety Monitor compatible model, certain modeling inconsistencies and system alignment issues were identified and the model was revised to address these issues. This second update incorporated LERF and shutdown models to form an integrated model.

The most recent update incorporated features affecting both units, such as system cross connection, improving ease of use for assessing overall risk of the two unit plant.

Through the evolution of the model, analysts accomplished significant enhancements to fault tree modeling, both at the system level and in the top logic. These enhancements and changes are summarized as follows:

- Revising model structure to represent a linked fault tree for linked model quantification
- Updating the Thermal-Hydraulics analysis used to develop accident sequences, including using MAAP 4.0 vs MAAP 3.0 to evaluate the postulated scenarios
- Improved documentation and level of detail associated with the six systems not fully developed under the original IPE effort
- Reflecting as built and plant changes since 1992
    1. *Procedure Changes*
       -Crediting changes associated with EOP updates (from IPE insights)
       -Incorporation of revised Tech Spec impacts
    2. *Plant Modifications*
       -Reactor Coolant Pump seal upgrade to high temperature seals
       -Addition of individual inverter room cooling units
       -Addition of spare inverters
    3. *Operational History*
       -Component failure rates and unavailabilities with plant-specific data where available
       -Industry initiating events, in particular LOCA frequencies (to newest NRC guidance)
       -Initiating event frequencies with plant-specific data where available
       -Frequencies of Loss-of-Offsite Power (LOOP), and LOOP Recovery
- Detailed review of latent human error, dynamic and recovery analysis, resulting in reduction of human error probabilities
- Updating the model to reflect more systematic recovery analysis and application
- Integrating ISLOCA sequences directly into the fault tree logic
- Providing detail representing opposite unit configuration
- Modifying SGTR sequences to ensure adequate consideration of long term cooling (beyond 24 hours) to address a key observation from the WOG Peer Review team

Current PRA Model

The primary suite of computer codes used to develop, maintain and quantify the current version (July 2001) of the CPSES PRA model is the **EPRI-developed R&R Workstation**; it includes the following codes:

- Computer Aided Fault Tree Analysis (CAFTA®)
- Event Tree Analysis (ETA®)
- PRA Quantification (PRAQUANT®)
- Cut Set Editor (CSED®)
- Safety Monitor
- (ORAM)

Prior Use of PRA for RI-IST Submittal

In November 1995, CPSES submitted a request for an exemption from the requirements (testing frequency) of 10CFR50.55a(f)(4)(I) and (ii). This request is commonly referred to as the Risk Informed In-Service Testing (RI-IST) submittal. Specifically, CPSES requested approval to utilize a risk-based in-service testing program to determine in-service test frequencies for valves and pumps that are identified as less safety significant, in lieu of testing those components per the frequencies specified by the AMSE code.

In August 1998, the USNRC provided a Safety Evaluation Report (SER) to CPSES with respect to the RI-IST request, and approved the request. As part of their review of the RI-IST submittal, the NRC performed an in-depth review of the CPSES PRA model of record at that time, the original IPE and IPEEE submittal. The focus of the NRC's review was to establish that the CPSES PRA appropriately reflected the plant's design and actual operating conditions and practices, and that there was a suitable technical basis to support the PRA-related findings made to support the Safety Evaluation Report.

To reach specific findings regarding the quality of the PRA, a focused-scope evaluation was performed by NRC staff that concentrated on elements of the PRA affected by the RI-IST application, and on the assumptions and elements of the PRA model which drive the results and conclusions. The major conclusions drawn by the NRC staff were:

> "The PRA addresses most of the potentially significant risk contributors and is adequate to provide insights on the plant risk and to provide input to the component categorization process used in the RI-IST submittal. Potentially important risk contributors from seismic events and from the low power and shutdown modes of operation are adequately addressed in the integrated decision making process."
>
> "A review of the PRA showed that the models are sufficiently detailed to include pumps and valves (and the important failure modes) required to prevent or mitigate the effects of the initiating events modeled. In addition, the PRA is of sufficient detail that system and operator dependencies important to the plant risk are included."
>
> "There is reasonable assurance of PRA adequacy, as shown by the licensee's process to ensure quality, and by a focused-scope review by the staff which shows that the components affected by the RI-IST process and those that are important to the decision making are appropriately modeled."

ENCLOSURE 2 to TXX-03024

Comanche Peak Steam Electric Station (CPSES) Significance Determination Process (SDP) Phase 3 Analysis

Evaluation of CPSES Unit 1 Steam Generator #2 Tube Leak

Revision 1

Engineering Analysis

February 2003

Prepared by: ____________ Date: 2-28-03
D. M. Tirsun

Reviewed by: Robert H. Lichtenstein Date: 3-3-03
R. H. Lichtenstein

Approved by: S.D. Karpyak Date: 3-4-03
S. D. Karpyak

1. PURPOSE

CPSES Unit 1 was scheduled to shutdown for Refueling Outage #9 on October 5, 2002. However, the Unit was conservatively shutdown on September 28, 2002 at 0140 when primary to secondary leakage from Steam Generator 2 showed an increase above predetermined management setpoints. The impact of this tube leak on core damage frequency and large early release frequency are assessed in this evaluation. The bases for the flawed tube characteristics and rupture probability used in this evaluation are provided in Westinghouse letter, WPT-16414 – "Steam Generator Tube Burst Pressure Estimate". [WPT-16417, Westinghouse Proprietary Class 2]

[This revision (Revision 1) provides enhanced descriptions and validates frequencies of the Plant Damage States used in this evaluation. The methodology employed in this evaluation is based on that used in the CPSES IPE filed in 1992.]

2. DISCUSSION

On September 26, 2002, Unit 1 was in "coastdown" to 1RF09 that was scheduled to start October 5, 2002 when indication of a Primary-to-Secondary Steam Generator Tube Leak (SGTL) was observed. Information obtained from Chemistry, the Unit 1 Reactor Operator electronic log, and various other sources was provided to Plant Management relative to the event. Plant Management conservatively shutdown the unit on 09/28/2002 (Saturday), about 0130 hrs, due to increased frequency and volume of the steam generator tube leak. At no time during the event did plant personnel have indication the leak exceeded 55 gpd, which is well below the Technical Specification 3.4.13.e shutdown requirement of 150 gpd.

3. EVALUATION

3.1 Areas to Assess within the Risk Assessment

In order to assess the risk associated with a leaking tube, it is first necessary to determine the potential impact of the condition on core damage frequency (CDF) and large early release frequency (LERF). These potential impacts are then compared to the baseline CDF and LERF levels and the resulting ΔCDF and ΔLERF are used to determine the potential severity of the condition. The following paragraphs identify how the PRA model is used to assess the impact of the tube leak.

It is also important to recognize that most SGTR core damage sequences, although they may bypass containment, are not early and may not be large (iodine release in the 5-15% range). Early relates to the time available after core damage for sheltering or evacuating the exposed population. Because classic SGTR sequences require long periods of time (and operator and equipment failures) to lead to core damage, early release is not likely. However, for conservatism in this analysis, all potential SGTR sequences, both direct SGTR sequences and induced SGTR sequences, are assumed to contribute to the calculated LERF.

Also important to recognize is that very few accident sequences have the potential to introduce a high enough delta pressure across the tubes to cause a tube rupture as part of the accident sequence. These are the high RCS pressure/dry Steam Generator sequences that are addressed in Section 3.2.4 below. Although certain transients (e.g. loss of Main Feedwater) have the potential to introduce a somewhat higher than normal operating delta pressure across the tubes, the design basis event is the Main Steam Line Break (MSLB). In this analysis MSLB and transients that can induce a Steam Generator Tube Rupture are handled in Section 3.2.3 and 3.2.4, respectively.

3.1.1 Potential Increase in SGTR Initiating Event Frequency (Spontaneous Tube Rupture)

The PRA Model includes a Steam Generator Tube Rupture as one of its initiating events. The frequency of a Tube Rupture (1.75E-03/generator/year) is based on industry experience. If the plant had remained at power, there may have been some increased potential for a SGTR.

3.1.2 Potential Increase in SGTR Induced by Steam-Side Depressurization

The calculations performed to support the accident sequence progression portion of the PRA Model include best estimate analysis with respect to expected plant responses including temperatures and pressures. The bases of these analyses assume that the plant is designed and configured to withstand its design basis accidents without inducing additional equipment failures. The presence of a degraded tube places the plant in a position where some of the transients evaluated as part of the PRA may have the potential to result in an "almost simultaneous" SGTR due to the pressure differentials induced across the SG tubes. The most limiting of these scenarios is the Main Steam Line Break (MSLB) scenario. In a MSLB, the SGs will experience pressure differentials that are about twice as severe as normal pressure differentials across the SG tubes. To assess this potential for an "almost simultaneous" SGTR, the potential for normal transients to result in a SGTR needs to be evaluated.

3.1.3 Potential Increase of Induced SG Tube Ruptures

Some core damage sequences created by initiating events that have nothing to do with Steam Generator tubes need to be considered. The core damage sequences of concern are characterized by relatively high RCS pressures and dry steam generators. These conditions subject Steam Generator tubes to delta pressures equivalent to MSLB delta pressures. The effects of tube degradation on these sequences is a potential increase in the probability that containment bypass will occur for accidents already included in the baseline Core Damage Frequency.

3.1.4 Exposure Time Associated with a Degraded Tube

The initiating event frequencies used in the PRA are all based on the likelihood of the initiating event occurring during a reactor year of operation. In order to assess the likelihood of the tube leak propagating into a tube rupture, it is important to determine the amount of time the tube was potentially susceptible to an increased potential for rupture.

This exposure time will be used to calculate the incremental conditional core damage probability (ICCDP) and incremental large early release probability (ICLERP).

3.2 Analysis of the Situation

The CPSES PRA model was used to assess the potential risk impact of the tube leak by focusing on the issues identified above. The actual approaches and results are discussed below. In order to assess the complete situation, the following approach was taken:

3.2.1 Identify the Baseline Risk Levels:

The baseline risk levels were established by quantifying the CPSES PRA model of record at a truncation level of 4E-10 for Core Damage Frequency (CDF) and at a truncation level of 5E-11 for Large Early Release Frequency (LERF). Two separate quantification runs were performed: one with all Test and Maintenance (T&M) events set to zero to be consistent with the methodology employed in the Nuclear Regulatory Commissions (NRC) Significance Determination Process (SDP), and one using the nominal T&M unavailability values. For both of these quantification runs the nominal baseline configuration flag file was used. The results of the baseline risk evaluation are:

$CDF_{\text{Base No T\&M}}$ = 9.590E-06/year $CDF_{\text{Base With T\&M}}$ = 1.763E-05/year
$LERF_{\text{Base No T\&M}}$ = 4.864E-07/year $LERF_{\text{Base With T\&M}}$ = 7.107E-07/year

3.2.2 Evaluate the Potential Increase in SGTR Initiating Event Frequency (Spontaneous Tube Rupture)

In situ testing of the leaking tube was conducted during 1RF09. In situ measurements showed that the leakage rate at Normal Operating Temperature (NOT) ΔP was ~ 29 gallons per day (gpd). With this information and other inspection data, the tube flaw was characterized. Using a burst simulation model, with inputs of flaw characteristics, material properties and material property distributions, an estimate was made of the number of times out of a thousand simulations that the tube would burst at normal operating pressures. The results of these CPSES-specific simulations show that there were no spontaneous rupture instances in a thousand simulations for a burst pressure less than 1922 psid. The results of these simulations show that the leaking tube was of sufficient strength to withstand normal operating temperature pressure differentials of approximately 1260 psid. Based on these facts, the potential for the leaking tube to have progressed to the stage where it was susceptible to rupture, or for the tube to have ruptured due to the pressures induced during a controlled shutdown is within the nominal initiating event frequency for SGTRs. For conservatism, however, the PRA model was re-quantified with the SGTR frequency for the Unit 1 Steam Generator 02 increased from 1.75E-03/generator/year to 2.75E-03/generator/year. The results of this risk evaluation are:

$CDF_{\text{Init No T\&M}}$ = 9.604E-06/year $CDF_{\text{Init With T\&M}}$ = 1.765E-05/year
$LERF_{\text{Init No T\&M}}$ = 4.997E-07/year $LERF_{\text{Init With T\&M}}$ = 7.318E-07/year

3.2.3 Evaluate the Potential Increase in SGTR Induced by Steam-Side Depressurization

As discussed in Section 3.1.2, the presence of a degraded tube places the plant in a position where some of the transients evaluated as part of the PRA may have the potential to result in an "almost simultaneous" SGTR due to the pressure differentials induced across the SG tubes. To evaluate this potential, the results of the in-situ testing performed on the degraded tube and the results of the corresponding burst simulation model were reviewed to identify the potential for an induced tube rupture based on physical characteristics of the tube prior to it exhibiting detectable leakage. Attachment 2 discusses the burst simulation model results over various time periods. The probability of burst associated with each of these time periods was used in this analysis.

3.2.4 Evaluate the Potential Increase in Induced SGTR

3.2.4.1 Frequency for LERF Considerations With a Degraded Tube

Induced steam generator tube ruptures have the potential for increasing the likelihood of a bypass scenario if a tube is degraded. These induced steam generator tube rupture scenarios impact LERF. Even when a degraded tube exists, for an induced SGTR (ISGTR) to occur, specific conditions must exist in the steam generators (high pressure on the RCS side, and low secondary side pressure associated with no water on the secondary side). Since only specific sequences have the potential to create the environment in the RCS and the steam generators that can result in an ISGTR, it is necessary to determine which plant damage states contain these types of sequences. A review of all plant damage states identified 6 PDSs containing sequences that have the potential to induce a SGTR. These 6 PDSs are: 3H, 3F, 4H, 4F, 3SBO, and 4SBO. Attachment 1 discusses the characteristics of the sequences that are binned into each of these PDSs. Attachment 2 discusses the conditional probabilities of induced tube rupture associated with each PDS based on physical tube characteristics at different times in the operating cycle, and the exposure times associated with each conditional probability of induced tube rupture.

3.2.4.2 Frequency for LERF Considerations With a Leaking Tube

The main difference between operating with a potentially degraded tube and a tube that is exhibiting known leakage, is the higher susceptibility to induced rupture at lower pressure differentials. Once the Steam Generator tube exhibited signs of leakage, there may be an increased potential for an induced burst.

3.2.5 Identify the Exposure Time that Should be Associated with a Degraded Tube

Since the tube was only susceptible to the increased induced failure rates for the time that the tube was significantly degraded, the exposure time used in the analysis needs to reflect the potential susceptibility period. Based on the insitu testing, and the burst simulation model, the tube was determined to be potentially susceptible to an small increased induced failure rate beginning at mid-cycle; 9 months prior to unit shutdown if it were exposed to MSLB pressure differentials. These same models and tests showed that, for normal operating pressure differentials, the potential probability of burst is negligible. For conservatism, all of the analyses will use a total of 9 months exposure time.

4. RESULTS

Based on the analysis performed and documented above, Incremental Conditional Core Damage Probabilities and Incremental Large Early Release Probabilities can be calculated. As shown below, each of the calculated values is well below the thresholds for risk significance, and the cumulative impact of the scenarios is also well below the thresholds.

4.1 Potential Increase in SGTR Initiating Event Frequency (Spontaneous Tube Rupture)

4.1.1 ICCDPs Calculated for the Potential Increase in SGTR Initiating Event Frequency (Spontaneous Tube Rupture)

For this scenario, the information on CDFs presented in Sections 3.2.1 and 3.2.2 and an exposure time of 9 months was used. Based on these inputs, the following ICCDPs have been calculated:

$ICCDP_{\text{With T\&M}} = (CDF_{\text{Init With T\&M}} - CDF_{\text{Base With T\&M}}) * (\text{Exposure Time})$
$ICCDP_{\text{With T\&M}} = (1.765E\text{-}05/\text{year} - 1.763E\text{-}05/\text{year}) * (9 \text{ months}) * (1 \text{ year}/12 \text{ months})$
$\mathbf{ICCDP_{\text{With T\&M}} = 1.50E\text{-}08}$

$ICCDP_{\text{No T\&M}} = (CDF_{\text{Init No T\&M}} - CDF_{\text{Base No T\&M}}) * (\text{Exposure Time})$
$ICCDP_{\text{No T\&M}} = (9.604E\text{-}06/\text{year} - 9.590E\text{-}06/\text{year}) * (9 \text{ months}) * (1 \text{ year}/12 \text{ months})$
$ICCDP_{\text{No T\&M}} = 1.05E\text{-}08$

4.1.2 ICLERPs Calculated for the Potential Increase in SGTR Initiating Event Frequency (Spontaneous Tube Rupture)

For this scenario, the information on LERFs presented in Sections 3.2.1 and 3.2.2 and an exposure time of 9 months was used. Based on these inputs, the following ICLERPs have been calculated:

$ICLERP_{\text{With T\&M}} = (LERF_{\text{Init With T\&M}} - LERF_{\text{Base With T\&M}}) * (\text{Exposure Time})$
$ICLERP_{\text{With T\&M}} = (7.318E\text{-}07/\text{year} - 7.107E\text{-}07/\text{year}) * (9 \text{ months}) * (1 \text{ year}/12 \text{ months})$
$\mathbf{ICLERP_{\text{With T\&M}} = 1.58E\text{-}08}$

$ICLERP_{\text{No T\&M}} = (LERF_{\text{Init No T\&M}} - LERF_{\text{Base No T\&M}}) * (\text{Exposure Time})$
$ICLERP_{\text{No T\&M}} = (4.997E\text{-}07/\text{year} - 4.864E\text{-}07/\text{year}) * (9 \text{ months}) * (1 \text{ year}/12 \text{ months})$
$ICLERP_{\text{No T\&M}} = 9.98E\text{-}09$

4.2 Potential Increase in SGTR Induced by Steam-Side Depressurization

4.2.1 ICLERPs Calculated for the Potential Increase in SGTR Induced by Steam-Side Depressurization

To evaluate the risk increase associated with the degraded tube potentially bursting at MSLB pressures, the following analysis was performed. The frequency of an MSLB was multiplied by the probability of the degraded tube rupturing at MSLB pressures. This frequency of rupture following an MSLB was then multiplied by the conditional core damage probability associated with a Steam Generator Tube Rupture and the exposure time associated with the condition to determine the potential of the scenario to result in core damage.

$ICCDP_{MSLB}$ = (MSLB Frequency) x (Burst Probability) x (SGTR CCDP) x (Exposure Time)

For this scenario, the time interval information provided in attachment 2 was used to calculate the ICCDPs associated with each time step. Table 4.2.1-1 summarizes the results of the calculations performed.

Table 4.2.1-1: Summary of **$ICCDP_{MSLB}$** Calculations

Time Step Going Forward from Mid-Cycle (months)	MSLB Frequency (per year)	SGTR CCDP	Burst Probability	Exposure Time (months)	Calculated $ICCDP_{MSLB}$
t = 0 to 4.5	1.90E-02	1.65E-05	0.004	4.5	4.70E-10
t = 4.5 to 6	1.90E-02	1.65E-05	0.009	1.5	3.53E-10
t = 6 to 7	1.90E-02	1.65E-05	0.015	1	3.92E-10
t = 7 to 8	1.90E-02	1.65E-05	0.024	1	6.27E-10
t = 8 to 8.9	1.90E-02	1.65E-05	0.039	.9	9.17E-10
t=8.9 to 9	1.90E-02	1.65E-05	0.072	.1	1.88E-09
Total					**2.95E-09**

Although the timing of when core damage occurs is not explicitly known, it is known that each of the scenarios associated with this analysis involve a Steam Generator Tube Rupture. Therefore, it can be conservatively assumed that each of the scenarios would also be classified as a Large, Early Release. Because of the one-to-one correlation assumption, the $ICCDP_{MSLB}$ also represents the $ICLERP_{MSLB}$.

4.3 Potential Increase in Induced SGTR Frequency

4.3.1 ICLERPs Calculated for the Potential Increase in Induced SGTR Frequency for a Degraded Tube

The calculations associated with each of the time steps delineated in Appendix 2 have been summed to determine the total calculated PDS dependent ISGTR probability associated with operating with the degraded tube. Table 4.3.1-1 shows the calculated PDS dependent ISGTR probability for each time step, and the cumulative probability.

Table 4.3.1-1: Calculated PDS Dependent ISGTR Probabilities

Time Step Going Forward from Mid-Cycle (months)	Calculated PDS Dependent ISGTR Probability
t = 0 to 4.5	7.10E-09
t = 4.5 to 6	5.33E-09
t = 6 to 7	5.92E-09
t = 7 to 8	9.47E-09
t = 8 to 8.9	1.38E-08
t=8.9 to 9	2.84E-09
Total	4.45E-08

To determine the increase in risk associated with operating with the degraded tube over normal operations without a known degraded tube, the calculated PDS Dependent ISGTR Probability based on the original ISGTR Conditional Probabilities must be subtracted from the value shown in Table 4.3.1-1. The calculated PDS Dependent ISGTR Probability based on the original ISGTR Conditional Probabilities is 7.59E-09 (see Table 6 of Attachment 2). Therefore, the increase in calculated PDS dependent ISGTR probability over the 9-month exposure time is:

ICLERP for PDS Dep ISGTR Prob = PDS Dep ISGTR $\text{Prob}_{\text{TUBE}}$ – PDS Dep ISGTR $\text{Prob}_{\text{ORIG}}$
ICLERP for PDS Dep ISGTR Prob = 4.45E-08 – 7.59E-09
ICLERP for PDS Dep ISGTR Prob = 3.69E-08

The effects of tube degradation on these sequences is a potential increase in the probability that containment bypass will occur for accidents already included in the baseline Core Damage Frequency. Although the timing of when core damage occurs is not explicitly known, it is known that each of the scenarios associated with this analysis involve a Steam Generator Tube Rupture. Therefore, it can be conservatively assumed that each of the scenarios would also be classified as a Large, Early Release.

5. SUMMARY OF RESULTS AND CONCLUSIONS

The above evaluation is comprehensive in that it addresses both CDF/CDP and LERF/LERP considerations for direct Steam Generator Tube Rupture events and Induced Steam Generator Tube Rupture events. Based on the results of the scenarios as presented above and summarized in Table 5.1, the potential risk increase associated with the leaking tube is insignificant. For SDP Phase 3 considerations, the ICCDP of 1.79E-08 is less than 1.0E-06; the ICLERP of 5.57E-08 is less than 1.0E-07. Therefore, the condition results in a green category.

Table 5.1: Summary of Results

Section Number	ICCDP	ICLERP
4.1.1	1.50E-08	1.58E-08
4.2.1	2.95E-09	2.95E-09
4.3.1	N/A	3.69E-08
Total	1.79E-08	5.57E-08

It is also important to recognize that these evaluations are conservative for three primary reasons. The first reason is that most SGTR core damage sequences, although they may bypass containment, are not early and may not be large (iodine release in the 5-15% range). Early relates to the time available after core damage for sheltering or evacuating of the exposed population. Because classic SGTR sequences require lots of time (and operator and equipment failures) to lead to core damage, early release is not likely. However, for conservatism in this analysis, all potential SGTR sequences, both direct SGTR sequences and induced SGTR sequences, were assumed to contribute to the calculated LERF.

The second reason is that, a steam side depressurization of a SG that causes tube failure must include the likelihood of the break and failure of isolation (if the break is downstream of the MSIVs). By including the Main Steam Line break failure likelihood and MSIV isolation failure, the initiating event frequency, even assuming a guaranteed failure of a degraded tube, should be ~8E-05 per year [(1.90E-02 MSLB per year) x (4.06E-03 for MSIV failure)] . For this analysis, the SGTR initiating event frequency was increased by 1E-3 per year, which is well above the frequency that would be realistic given the requirements associated with generating a tube rupture following a transient event.

The third reason is that the tube rupture burst prediction model used is conservative in predicting burst probabilities at MSLB delta pressures. The model assumes that the flaws observed act as a single flaw rather than individual flaws. This assumption results in higher burst probabilities being calculated.

Attachment 1

The CPSES Plant Damage States (PDS) are developed by combining the core damage state attributes with the containment safeguards status. The station blackout (SBO), the containment bypass and isolation failure core damage bins are not combined with the containment safeguards bins because those are implied by the core damage state. Each PDS is defined as a group of core damage sequences that have similar characteristics with respect to the severe accident progression and containment response. The core damage states and containment safeguards bins of interest for this evaluation are described below.

Core Damage Bin – 3: Sequence characteristics are high RCS pressure and leakage rates associated with boil-off of the reactor coolant through cycling pressurizer relief valves (not stuck open) or small seal LOCAs up to 60 GPM/Pump (0.6 inch diameter), with early core melt.

Core Damage Bin – 4: Sequence characteristics are high RCS pressure and leakage rates associated with boil-off of the reactor coolant through cycling pressurizer relief valves (not stuck open) or small seal LOCAs up to 60 GPM/Pump (0.6 inch diameter), with late core melt.

Core Damage Bin – ySBO: Sequence characteristics are Station Blackout sequences or equivalent equipment failures; y = 3 early melt, y = 4 late melt.

Containment Safeguards Bin – H: Sequence characteristics are those where both containment fan coolers and containment spray are failed.

Containment Safeguards Bin – F: Sequence characteristics are those where both containment fan coolers and containment spray are available.

The following paragraphs describe the distinguishing characteristics of the Plant Damage States of interest. These definitions were developed as part of the IPE and have remained unchanged since that time. Whereas the PDS values are changed to reflect the updated Level I PRA, remaining IPE Level II structure and values remain if effect as the reference point for interpreting results.

Plant Damage State 3H

This PDS groups Transients involving loss of all feedwater with residual heat removal (RH) and safety injection (SI) system failures at injection. While the centrifugal charging pumps (CCPs) may or may not be available, they do not inject until after vessel failure due to the high head and containment spray failure at injection. As previously discussed, these PDS involve the RCS at high pressure, with a 0.295 probability of not successfully depressurizing. The probability of not depressurizing is calculated based on the 'DP' (RCS Not Depressurized Before Vessel Breach) fault tree shown in the CPSES IPE Volume II – Backend Analysis, page 4-156. The operator action used in the fault tree (HOP-DP), as defined in the IPE, for failure to depressurize RCS associated with this PDS is 0.73. This operator action does not credit the SAMG-related actions.

Plant Damage State 3F

This PDS groups Transients involving loss of all feedwater with RH and SI system failures at injection. While the CCPs may or may not be available, they do not inject until after vessel failure due to the high head. In this PDS, containment sprays inject and switchover successfully to recirculation, so there is no containment failure due to steam overpressurization. This PDS nominally involves the RCS at high pressure, with a 0.0751 probability of not successfully depressurizing. The probability of not depressurizing is calculated based on the 'DP' (RCS Not Depressurized Before Vessel Breach) fault tree shown in the CPSES IPE Volume II – Backend Analysis, page 4-156. The operator action used in the fault tree (HOP-DP), as defined in the IPE, for failure to depressurize the RCS associated with this PDS is 0.17. This operator action does not credit the SAMG-related actions.

Plant Damage State 4H

This PDS groups Transients where the turbine drive auxiliary feedwater pump (TDAFW) operates for 4 hours after reactor trip and two CCPs inject on demand but fail at recirculation and containment sprays fail at injection. This PDS includes late containment failure probabilities due to steam over-pressurization that occur later in the scenario because the failure of containment sprays extends the duration of the ECCS injection period. As previously discussed, these PDS involve the RCS at high pressure, with a 0.371 probability of not successfully depressurizing. The probability of not depressurizing is calculated based on the 'DP' (RCS Not Depressurized Before Vessel Breach) fault tree shown in the CPSES IPE Volume II – Backend Analysis, page 4-156. The operator action used in the fault tree (HOP-DP), as defined in the IPE, for failure to depressurize the RCS associated with this PDS is 0.95. This operator action does not credit the SAMG-related actions.

Plant Damage State 4F

This PDS groups Transients where the TDAFW operates for 4 hours after reactor trip and ECCS injects successfully but fails at recirculation. Containment sprays inject and switchover successfully to recirculation, so there is no containment failure due to steam over-pressurization. The CET end-state probabilities for this event are identical to those discussed previously for PDS 3F except in this case the probability of not depressurizing is 0.384. This probability was calculated based on the 'DP' (RCS Not Depressurized Before Vessel Breach) fault tree shown in the CPSES IPE Volume II – Backend Analysis, page 4-156. The operator action used in the fault tree (HOP-DP), as defined in the IPE, for failure to depressurize the RCS associated with this is PDS 0.99. This operator action does not credit the SAMG-related actions.

Plant Damage States 3SBO

This PDS groups Station Blackouts involving simultaneous loss of all feedwater (Main Feedwater and Auxiliary Feedwater). This PDS involves the RCS at high pressure, with a 0.0225 probability of not successfully depressurizing. This value was calculated based on the 'DP' (RCS Not Depressurized Before Vessel Breach) fault tree shown in the CPSES IPE Volume II – Backend Analysis, page 4-156. The operator action used in the fault tree (HOP-DP), as defined in the IPE, for failure to depressurize the RCS associated with this PDS is 0.05. This operator action does not credit the SAMG-related actions.

Plant Damage States 4SBO

This PDS groups Station Blackouts involving loss of all feedwater after 4 hours of auxiliary feedwater being supplied by the TDAFW pump. This PDS involves the RCS at high pressure, with a 0.387 probability of not successfully depressurizing. This value was calculated based on the 'DP' (RCS Not Depressurized Before Vessel Breach) fault tree shown in the CPSES IPE Volume II – Backend Analysis, page 4-156. The operator action used in the fault tree (HOP-DP), as defined in the IPE, for failure to depressurize the RCS associated with this PDS is 1.0. This operator action does not credit the SAMG-related actions.

Calculation of Induced SGTR frequency by PDS

The ISGTR frequency for every high pressure PDS was calculated in the IPE by subtracting the probability of RCS depressurization as calculated for the base case (i.e. the case where the tube could fail) from the case where the tubes are intact. This difference is the probability that the depressurization is due to the induced failure of the tubes and is listed in the center column of Table 1. This is the factor that would be multiplied by the PDS frequency to obtain an unconditional ISGTR frequency for each PDS. The actual calculations of unconditional ISGTR frequencies are contained in Section 4.2.1 of the evaluation. The right hand column of Table 1 shows the contribution each PDS had towards the total ISGTR frequency reported in the IPE.

Table 1

PDS Name	ISGTR Conditional Probability (as reported in IPE) (1)	Percent of ISGTR Total (as reported in IPE)
3H	3.00E-03	37.58%
3F	1.00E-03	8.95%
4H	5.00E-03	9.95%
4F	5.00E-03	39.01%
3SBO	3.00E-04	0.10%
4SBO	5.00E-03	4.45%

1. Although the numbers in this table are taken from the original IPE submittal, the plant damage state definitions and their associated probabilities of successful depressurization have not changed from the originally reported values Therefore, these values also represent the ISGTR Conditional Probabilities associated with the current PRA model of record

As expected, because the 3SBO sequences have a high probability of successful depressurization, their ISGTR Conditional Probability is an order of magnitude lower than the ISGTR Conditional Probabilities associated with the other PDS categories.

Attachment 2

As shown in Attachment 1, all of the PDS categories, with the exception of 3SBO, have an ISGTR conditional probability between 1E-3 and 5E-3. The 3SBO category has an ISGTR conditional probability of 3E-4, which is an order of magnitude lower that the other PDS categories. This is expected, since this PDS has a very high probability of successful primary side depressurization.

To evaluate the potential impact on induced tube ruptures associated with operating with the degraded tube, the conditional probability of an ISGTR was modified for each of the impacted PDS categories. Because only certain scenarios are potentially susceptible to an induced SGTR, the conditional probability of an induced SGTR for each of these scenarios, except for the 3SBO plant damage state (PDS) scenarios, were increased from the nominal conditional probability used in the IPE. The probability used at each time step is based on the calculated probability of induced tube rupture that was calculated using the tube burst simulation software.

The incremental ISGT probability is associated with PDS categories 3H, 3F, 4H, 4F, 3SBO and 4SBO because they are the sequences where the core melts with the RCS at high pressure. This incremental ISGTR probability associated with the flawed tube was calculated by subtracting the ISGTR probability as calculated in the IPE from the ISGTR probability for the flawed tube calculated as explained below. In the IPE the ISGTR probability includes the possibility of competing RCS depressurization mechanisms including operator action (but not SMAG related actions), and surge line and hot leg failure using information from NUREG-1150. In the computation of the ISGTR probability for the flawed tube none of the competing depressurization mechanisms were included and only the tube failure probability itself (burst probability as determined by Westinghouse) was taken as the ISGTR probability. As a result of this approach, the baseline ISGTR is reduced due to the competing depressurization mechanisms where as the flawed ISGTR probability is not, thereby maximizing the differential. (An exception is made for the flawed ISGTR probability for PDS 3SBO where competing depressurization mechanisms are included by process of scaling as discussed below. This is justified because most of the scenarios in the 3SBO bin are successfully depressurized by operator action and therefore are more reasonably credited than competing phenomenological mechanisms.)

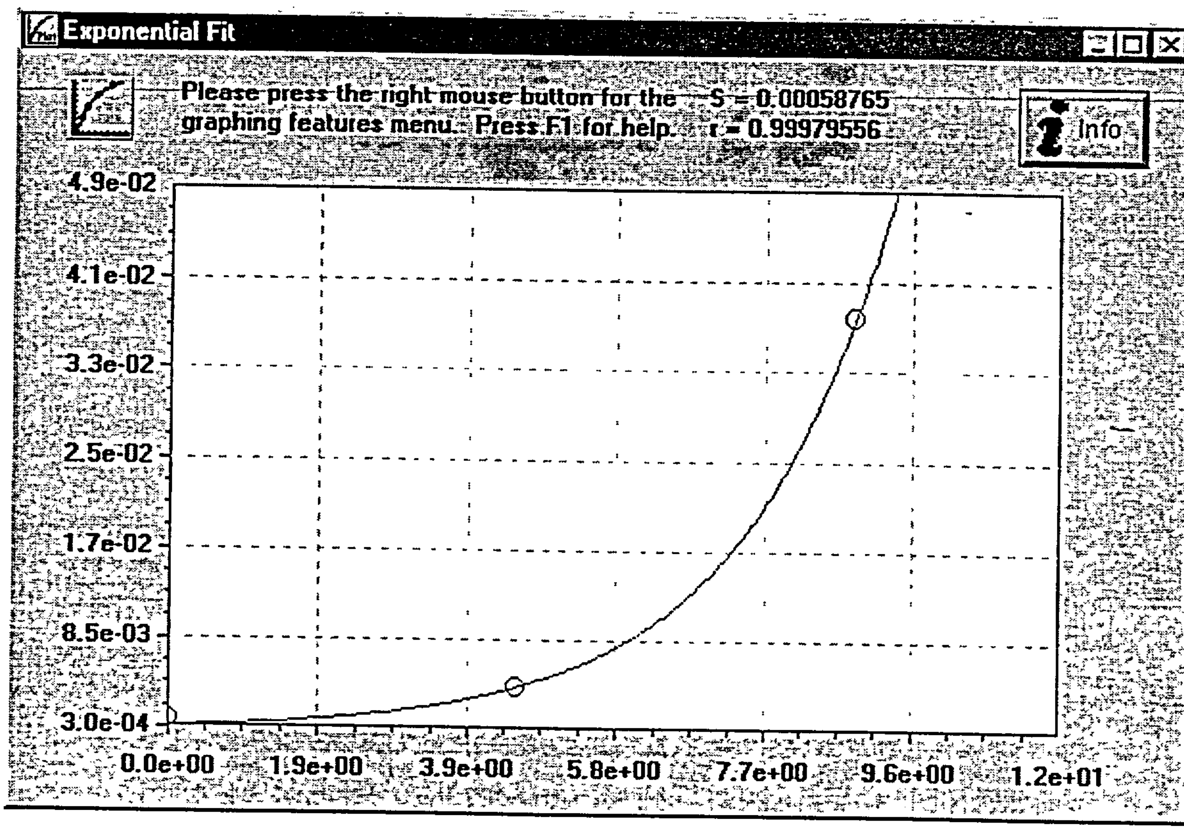
In order to determine an appropriate factor to apply to the 3SBO bin, a comparison was made between the 3SBO and 4SBO categories since the only differences between these categories was the probability of successful depressurization, and the successful 4 hour run of the TDAFW pump in the 4SBO sequences. A ratio of the ISGTR conditional probabilities associated with the 3SBO and 4SBO categories was used to determine the appropriate ISGTR conditional probability to be used in this analysis. The following calculation shows how this was accomplished, and the resulting ISGTR conditional probability calculated for 3SBO.

$$\frac{\text{Original 3SBO ISGTR Cond Prob}}{\text{Original 4SBO ISGTR Cond Prob}} = \frac{\text{New 3SBO ISGTR Cond Prob}}{\text{New 4SBO ISGTR Cond Prob}}$$

Results for the burst simulation at MSLB pressures are contained in Westinghouse letter LTR-SGDA-03-30. The degraded tube was shown to have a 1/1000 probability of induced rupture 9 months (mid-cycle) prior to exhibiting a detectable leak. The degraded tube was shown to have a 4/1000 probability of induced rupture 4.5 months (3/4 cycle) prior to exhibiting a detectable leak. On the date the tube exhibited a detectable leak, the burst simulation showed the tube to have a 39/1000 probability of induced rupture. At the time of plant shutdown (approximately three days after the detectable leak), the burst simulation showed the tube to have a 72/1000 probability of induced rupture. The burst simulation probability was assumed to follow an exponential curve for the first 8.9 months (from mid-cycle to the detectable leak). A conservative step change was then assumed from 8.9 months to 9 months due to the changes in tube leakage prior to shutdown. The probability for the 8.9 to 9 month period is simply assumed to be the shutdown value calculated by the burst simulation (.072). The formula calculated for the exponential curve from time 0 (mid-cycle) to 8.9 months is:

$$Y = 4.248E\text{-}04 \text{ EXP } (0.5049X)$$

The tube rupture burst prediction model used in these calculations is conservative in predicting burst probabilities. It assumes that the flaws observed in the tube act as a single flaw rather than individual flaws. This assumption results in a higher potential burst probability being calculated.



For this analysis, setting mid-cycle as time t = 0, the following six time intervals were used:

1. From mid-cycle (Time t = 0) to ¾ cycle (Time t = 4.5 months); Prob = 0.004
2. From ¾ cycle (Time t=4.5 months) to Time t = 6 months; Prob = 0.009
3. Time t = 6 months to Time t = 7 months; Prob = 0.015
4. Time t = 7 months to Time t = 8 months: Prob = 0.024
5. Time t = 8 months to Time t = 8.9 months (tube exhibited a leak); Prob = 0.039
6. Time t = 8.9 months to Time t = 9 months (tube exhibited a leak); Prob = 0.072

The following tables summarize the original ISGTR Conditional Probability, the ISGTR Conditional Probability being used in this analysis, and the PDS Frequency associated with each PDS based on the current CPSES PRA model of record.

Table 1: Time t = 0 to Time t = 4.5 months

PDS Name	IPE ISGTR Conditional Probability (1)	Increased ISGTR Conditional Probability	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	3.00E-03	4.00E-03	1.594E-07	4.5	2.39E-10
3F	1.00E-03	4.00E-03	3.307E-06	4.5	4.96E-09
4H	5.00E-03	4.00E-03	3.681E-08	4.5	5.52E-11
4F	5.00E-03	4.00E-03	4.833E-07	4.5	7.25E-10
3SBO	3.00E-04	2.40E-04	1.224E-05	4.5	1.10E-09
4SBO	5.00E-03	4.00E-03	1.289E-08	4.5	1.93E-11
Total					7.10E-09

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4 6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

Table 2: Time t = 4.5 to Time t = 6 months

PDS Name	IPE ISGTR Conditional Probability (1)	Increased ISGTR Conditional Probability	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	3.00E-03	9.00E-03	1.594E-07	1.5	1.79E-10
3F	1.00E-03	9.00E-03	3.307E-06	1.5	3.72E-09
4H	5.00E-03	9.00E-03	3.681E-08	1.5	4.14E-11
4F	5.00E-03	9.00E-03	4.833E-07	1.5	5.44E-10
3SBO	3.00E-04	5.40E-04	1.224E-05	1.5	8.26E-10
4SBO	5.00E-03	9.00E-03	1.289E-08	1.5	1.45E-11
Total					5.33E-09

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4 6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

Table 3: Time t = 6 to Time t = 7 months

PDS Name	IPE ISGTR Conditional Probability (1)	Increased ISGTR Conditional Probability	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	0.003	0.015	1.594E-07	1	1.99E-10
3F	0.001	0.015	3.307E-06	1	4.13E-09
4H	0.005	0.015	3.681E-08	1	4.60E-11
4F	0.005	0.015	4.833E-07	1	6.04E-10
3SBO	0.0003	0.0009	1.224E-05	1	9.18E-10
4SBO	0.005	0.015	1.289E-08	1	1.61E-11
Total					5.92E-09

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4 6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

Table 4: Time t = 7 to Time t = 8 months

PDS Name	IPE ISGTR Conditional Probability (1)	Increased ISGTR Conditional Probability	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	3.00E-03	2.40E-02	1.594E-07	1	3.19E-10
3F	1.00E-03	2.40E-02	3.307E-06	1	6.61E-09
4H	5.00E-03	2.40E-02	3.681E-08	1	7.36E-11
4F	5.00E-03	2.40E-02	4.833E-07	1	9.67E-10
3SBO	3.00E-04	1.44E-03	1.224E-05	1	1.47E-09
4SBO	5.00E-03	2.40E-02	1.289E-08	1	2.58E-11
Total					9.47E-09

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4.6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

Table 5: Time t = 8 to Time t = 8.9 months

PDS Name	IPE ISGTR Conditional Probability (1)	Increased ISGTR Conditional Probability	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	0.003	0.039	1.594E-07	0.9	4.66E-10
3F	0.001	0.039	3.307E-06	0.9	9.67E-09
4H	0.005	0.039	3.681E-08	0.9	1.08E-10
4F	0.005	0.039	4.833E-07	0.9	1.41E-09
3SBO	0.0003	0.00234	1.224E-05	0.9	2.15E-09
4SBO	0.005	0.039	1.289E-08	0.9	3.77E-11
Total					1.38E-08

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4 6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

Table 5A: Time t = 8.9 to Time t = 9 months

PDS Name	IPE ISGTR Conditional Probability (1)	Increased ISGTR Conditional Probability	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	0.003	0.072	1.594E-07	0.1	9.57E-11
3F	0.001	0.072	3.307E-06	0.1	1.98E-09
4H	0.005	0.072	3.681E-08	0.1	2.21E-11
4F	0.005	0.072	4.833E-07	0.1	2.90E-10
3SBO	0.0003	0.00432	1.224E-05	0.1	4.41E-10
4SBO	0.005	0.072	1.289E-08	0.1	7.73E-12
Total					2.84E-09

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4 6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

Table 6: Original Model over 9 Month Exposure Time

PDS Name	IPE ISGTR Conditional Probability (1)	PRA Model of Record PDS Frequency (per year) (2)	Exposure Time (months)	Calculated PDS Dependent ISGTR Probability
3H	3.00E-03	1.594E-07	9	3.59E-10
3F	1.00E-03	3.307E-06	9	2.48E-09
4H	5.00E-03	3.681E-08	9	1.38E-10
4F	5.00E-03	4.833E-07	9	1.81E-09
3SBO	3.00E-04	1.224E-05	9	2.75E-09
4SBO	5.00E-03	1.289E-08	9	4.83E-11
Total				7.59E-09

(1) RXE-92-01B, IPE CPSES Volume II, Backend, October 1992, Table 4 6-18
(2) Generation of PDS BIN Frequencies for Steam Generator Tube Leak Issue PRA Log # 81a

ENCLOSURE 3 to TXX-03024

Comanche Peak Steam Electric Station (CPSES)
Vendor Analysis of Defect