SAFETY EVALUATION BY THE NUCLEAR REGULATORY COMMISSION

RELATING TO THE RESTART OF THE

FORT CALHOUN STATION, UNIT NO. 1

FACILITY OPERATING LICENSE NO. DPR-40

OMAHA PUBLIC POWER DISTRICT

DOCKET NO. 50-285

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1.0 Introduction

At approximately 4:50 p.m. on May 16, 1984, the Fort Calhoun Station, Unit No. 1 experienced a tube failure in the B steam generator. Prior to the transient, the station's reactor coolant system was being pressurized in order to perform a hydrostatic pressure test. As the pressure was being raised toward the test pressure, operating personnel observed an unanticipated increase in the water level in the B steam generator. The operating personnel determined that the most probable cause of the unexpected water level increase was a result of a tube failure, and action was taken to depressurize the reactor cooling system. The system was depressurized in a few minutes; it was cooled down in a few hours. No offsite releases of radioactivity occurred as a result of the failure.

By letter dated June 5, 1984, from J. T. Collins (NRC) to W. C. Jones (OPPD), the NRC confirmed actions proposed by OPPD. Those actions included further eddy current testing of both steam generators, independent verification of the results, a safety analysis supporting station return to service, and maintaining the station in the refueling mode until NRC approval for restart.

Omaha Public Power District has performed extensive evaluations related to the tube failure event. The evaluations were submitted by letters dated May 22, 1984, May 31, 1984, and June 19, 1984. The May 22, 1984, letter contained a summary of the event. The May 31, 1984, letter contained the specific details of the event, a description of past steam generator inspections, and the results of the failed tube visual inspections and laboratory analyses. The June 19, 1984, letter contained an update of the information presented in the May 31, 1984, letter. A draft of the June 19, 1984, submittal was submitted to the NRC staff by letter dated June 18, 1984. A meeting was also held at the NRC offices in Bethesda, Maryland on May 29, 1984. The May 31, 1984, submittal documented the meeting discussions.

OPPD committed to provide a final report relating to the tube failure mechanism by June 30, 1984.

The purpose of this Safety Evaluation is to determine if the Fort Calhoun Station, Unit No. 1 is safe to return to power operations. To do this, the staff has reviewed the licensee's submittals as described above.

This report is comprised of three major sections. The first, Section 2, is the event discussion. Section 3 contains the details of the licensee's steam generator inspections, plugging, and tube failure analyses. The final major section discusses the licensee's future operation-related activities. It is further divided into sections on leakage detection improvements, sampling frequency improvements, procedure reviews, and licensed operator refresher training.

2.0 Steam Generator B Tube Failure Event

The Fort Calhoun Station, Unit No. 1 is a two-loop pressurized water reactor. It is owned and operated by the Omaha Public Power District (OPPD). OPPD (the licensee) is authorized to operate the station at steady state reactor core power levels not to exceed 1500 megawatts thermal. The design electrical rating is 478 megawatts electric (net). Each of the two reactor coolant loops contains a steam generator, two pumps, loop piping and instrumentation. Pressure in the system is controlled by the pressurizer, where water and steam pressure is maintained through the use of electrical heaters and sprays.

The heat generated in the reactor is removed from the core by the reactor coolant (water) and transported to the steam generators. The steam generators transfer the heat from the primary coolant passing through the U-tubes to the water in the secondary side of the steam generator, causing the secondary water to boil. The primary coolant, after giving up its heat, is returned to the reactor vessel where it will again be heated.

The steam generated in the steam generators then flows via the main steam lines to the turbine-generator where electricity is produced. The exhaust from the main turbine is condensed and then pumped through the feedwater heaters back to the steam generators where it will again be turned into steam as it repeats the above cycle.

The station was shut down for refueling on March 2, 1984. Prior to shutdown, in Februry 1984, the operators discovered a very small primary-to-secondary leakage in the B steam generator. Based on comparison of primary-to-secondary coolant activities, the leakage rate was determined to be approximately 0.2 gallons per day. The licensee's technical specifications allow primary-to-secondary leakage of up to one gallon per minute, at which time corrective actions must be taken, including station shutdown. Since a small amount of leakage was detected before shutdown, the licensee decided to augment his normal steam generator tube testing program to find the small leakage. The licensee's augmented program included eddy current testing of a large number of tubes in both steam generators, helium testing, and dye testing. The licensee could not find the leak and decided to return the station to service.

One of the tests that the licensee performs after a refueling outage and prior to station service is a hydrostatic pressure test of the reactor coolant system. The minimum test pressure is 2150 psia. This is above the normal operating system pressure of 2100 psia. If the reactor coolant system does not leak at the test pressure, it is assumed that it will not leak during normal operations.

The pressure test was underway on May 16, 1984. The reactor coolant system pressure was being raised toward the test pressure. The B steam generator secondary pressure was approximately 200 psig. The operators were paying particular attention to the B steam generator for they knew that it exhibited a very small leakage before the station shutdown. As the reactor coolant system pressure approached 1800 psia, the operators noted a decrease in the pressurization rate and also noted an unanticipated increase in the water level in the B steam generator. The operators determined that a major leakage was under way and they decided to depressurize and cooldown the reactor coolant system. The maximum leakage was estimated at approximately 110 gallons per minute based upon steam generator level measurements and chemical and volume control system (CVCS) charging flow. The maximum CVCS charging rate is 120 gallons per minute. Approximately 7500 gallons leaked from the reactor coolant system to the B steam generator. Although a large amount of water was introduced into the B steam generator, no water entered the main steam line associated with the steam generator.

The reactor coolant system was depressurized in a few minutes; it was cooled down in a few hours using the A steam generator and the atmosphere steam dump valve. Figure 1 illustrates the reactor coolant system pressure and the B steam generator water level as a function of time during the event. Table 1 contains a more detailed time history of the event, including initial conditions.

The licensee evaluated whether any offsite release of radioactivity occurred during the tube failure and subsequent to it. The licensee reported that no releases occurred. The licensee also activated the station's Radiological Emergency Response Plan during the event and subsequent to it. The licensee did not report any problems with the plan's activation or termination.

We conclude that the licensee's operators always had full control of the station during the event and subsequent to it, and have acted responsibly. We also reaffirm the usefulness of preoperational testing of the station, for the failure occurred during a test to assure that the reactor coolant system was leak tight. Had the failure occurred during normal power operations, the operator responses would have been more challenging, the station would have experienced a more complicated transient, and there would probably have been an offsite release of radioactivity.

3.0 Steam Generator Inspections, Plugging, and Tube Failure Analyses

3.1 Discussion and Evaluation

Prior to the March 1984 refueling outage, the Fort Calhoun steam generators were operating with an 0.2 gpd primary-to-secondary leakage in the B steam generator. In an effort to locate the leak during the outage, helium leak tests were conducted before and after a sludge lancing with no success. A hydrostatic test with a dye indicator was not successful in locating the leak.

Eddy current examinations were then performed on 1454 tubes in steam generator A and 1034 tubes in steam generator B. The results showed dent-like indications, primarily at the No. 8 partial drilled hole support plate and in the batwing areas. Four (4) tubes in steam generator A and five (5) tubes in steam generator B required plugging due to restriction of the 0.540 eddy current probe, and a decision to perform a rim-cut modification on the No. 8 partial drilled hole support plates was made.

After the rim-cut modification, 120 peripheral tubes in steam generator A and 111 peripheral tubes in steam generator B were retested to determine whether there was any damage from the rim cutting. One (1) tube in steam generator A was plugged due to flame damage. Additional tubes were examined in steam generators A and B using eddy current techniques and approximately 50 tubes in steam generator A were examined with a profilometry probe in an effort to characterize dent-like indications. No additional tube plugging was required and on May 16, 1984, the plant started hydrostatic tests in preparation for return to power operation. During the hydrostatic test, when the reactor coolant system pressure was 1800 psi and the steam generator secondary side pressure was 200 psi, an unanticipated water level increase in steam generator B indicated a large tube leak which was later estimated at 110 gpm. The hydrostatic tests were discontinued and the plant was brought to shutdown conditions to investigate the tube failure.

The failed tube was located in the second peripheral row from the outside in steam generator B, identified as Row 29 Line 84. The failure was an axial "fishmouth" opening along the tube bottom on the hot-leg side of the horizontal run at the top of the "U". It was located between the scallop bars in the vertical batwing support. Sections of the failed tube and adjacent tube were removed for laboratory analyses.

The failed tube was one that had been the subject of eddy current testing in both 1982 and 1984. Review of the tapes of those tests showed no flaw in 1982, but revealed an indication of a defect through 99% of the wall in 1984. Although this indication was unambiguous and not affected by interference, it was missed by the analyst who evaluated the 1984 tapes before the hydrostatic test. A second flaw in the same tube was also apparent in the 1984 eddy-current tapes. All previously tested tubes were rereviewed for any discrepancies with the original findings.

Post tube-failure eddy-current testing was then conducted on all remaining accessible tubes in steam generators A and B, and the tapes were reviewed by a second analyst to preclude missing any pertinent indications. The testing was conducted using bobbin coil probes in the multifrequency mode. Additionally, 300 tubes in B steam generator were inspected using 1 x 8 and/or 4 x 4 pancake coil array so that potential interference from variables such as supports can be eliminated. Also, 276 of the 300 tubes were examined using 1 x 8 superflex profilometry to characterize denting in the vertical batwing strap areas. In steam generator A, 150 tubes were profiled.

The post-failure multifrequency tests were performed using 400 and 200 Khz differential and 300 and 100 Khz absolute frequencies. The 400 and 200 Khz signals were mixed to suppress the effects of the vertical support straps, and the 300 and 100 Khz signals were mixed to suppress the effects of the support plates and egg crates.

In addition, those tubes from the pre-tube failure inspections in the March 1984 program, which were not retested otherwise with bobbin coil or pancake array probe eddy current testing, were retested using a 100 Khz absolute test for enhanced defect sensitivity. The original program used 800 Khz instead of 100 Khz in order to minimize ID tube noise and allow better determination of denting in the No. 8 partial support plates.

The results of the above inspections were as follows:

STEAM GENERATOR A

Tubes Inspected/Multifrequency - 4955

Inaccessible - 24

Indications

$<$20% - 7
20-40% - 8
$>$40% - 2

Total No. of Tubes Plugged	- 13
Defective	- 2
Rim Cut Damage	- 1
Probe Restriction	- 4
Vertical Support H/L Indications	- 4
Indication Approaching Plugging Limit	- 1
H/L End of Partially Plugged Tube	- 1

STEAM GENERATOR B

Tubes Inspected/Multifrequency - 4970 Inaccessible - 11

Indications		Total No. of Tubes Plugged	- 12
< 20%	- 18	Defective	- 2
20-40%	- 5	Probe Restriction	- 5
> 40%	- 2	Tube Removed with Failed Tube	- 1
		Tube in Proximity of Failed Tube	- 1
		Misplugged with Failed Tube	- 1
		Vertical Support H/L Indications	- 2

Tubes Tested with 1 x 8 and/or 4 x 4 Pancake Array - 300

Indications (also seen with bobbin coil/multifrequency)
42% - 1

Profilometry data from 206 tubes in steam generator B has been analyzed. One hundred and forty-seven (147) of these tubes are in the outer areas of the tube bundle and pass through all three (3) vertical support straps and 59 tubes in the inner areas with only a single center vertical support strap. The largest dents were at the vertical support straps on the hot-leg side of the generator. Seventy-four (74) of the 147 tubes in the outer area of the tube bundle had dent indications at this location. Of the 59 tubes in the inner areas of the tube bundle, 21 had dent indications at the vertical strap but of lesser magnitude than dents in the outer area tubes which pass through all three (3) vertical straps. Denting was noted with increasing frequency as the row number increased. From Row 49 outward, nearly all tubes had a dent indication in the vertical support strap.

The profilometry data indicating relative dent size at each vertical support location are shown below:

TUBES WITH THREE (3) VERTICAL SUPPORTS
(147 TUBES PROFILED)

Location (Number of Dents)	Approximate Size of Dents (Number of Dents)		
	0-10 mils	10-20 mils	> 20 mils
Hot Leg (74)	(21)	(8)	(45)
Center (47)	(39)	(4)	(4)
Cold Leg (24)	(17)	(5)	(2)

TUBES WITH CENTER SUPPORT ONLY
(59 TUBES PROFILED)

Number of Dents	Approximate Size of Dents (Number of Dents)		
21	0-10 mils (18)	10-20 mils (3)	> 20 mils (0)

The test results of the profilometry examinations were compared with the bobbin coil examinations performed on the same tubes in the outer area locations, and it was noted that the bobbin coil was only able to detect 59.5% of the dents at the hot-leg vertical support strap. The overall results for all three (3) vertical support straps showed that the bobbin coil detected 41.5% of the dents detected by profilometry. The bobbin coil also showed smaller dent indications than those that were observed with profilometry. This was not unexpected, however, due to the differences in the two (2) test methods.

Sections of the failed tube, L29 R84, and the tube adjacent, L29 R86, removed for access, were subjected to visual examinations and laboratory analyses at Combustion Engineering's Laboratories in Windsor, Connecticut to determine the failure mechanism. Two (2) cracks were observed visually on the failed tube section. The first was a large, axial "fishmouth" type crack measuring 1 1/4", while the second was a series of small (approximately 1/4") length fissures which made an acute angle (45) relative to the axis of the tube. Using field eddy current test equipment, a 100% throughwall signal was identified at the location of the "fishmouth" failure and approximately 1/4 of an inch from the hot-leg end of the first defect, a second O.D. initiated defect signal was observed which corresponded to the second crack.

These results are comparable to the reanalysis of the June 1984 in-service steam generator ECT inspection data, wherein two (2) defect signals approximately 1/4" apart were identified. The first was approximately 100%, while the second was estimated at 50% throughwall.

The complete visual inspection consisted of documenting the as-received condition by videography. Subsequently, photomacrographs were taken to document the appearance of the tube section, including defect areas and areas of deposits. In particular, photographs were taken to illustrate the lower and upper scallop bar deposits, the overall appearance of the defects, the area between the two (2) defects, closeups of each defect, and finally the appearance of the fracture surface. The large crack was located at the 6 o'clock position in the steam generator, as confirmed by the relative position of the scallop bar contact areas.

Dimensional measurement indicates that the tube was ovalized. The major axis (6-12 o'clock) was elongated by 0.046-0.122 inch, while the minor axis (3-9 o'clock) was compressed by 0.045-0.070 inch diametrically.

Etched microstructures indicated typical mill annealed alloy 600 material that was not sensitized and chemical analyses also indicated no discrepancies with ASME specifications.

Metallographic examination revealed the presence of intergranular stress corrosion cracking (IGSCC). There was no evidence of the presence of a network of intergranular attack between the fissures.

The fracture surface was examined by scanning electron microscopy (SEM) to determine the relative amounts of IGSCC and ductile failure on the fracture surface.

Approximately 95% of the wall thickness exhibited a distinct intergranular appearance. Only a small amount of ductile tearing, approximately 5% of the wall thickness, was evident at the I.D. surface. The "fishmouth" fracture was thought to be formed from a series of essentially throughwall axially oriented intergranular penetrations, followed by ductile tearing of the material between the penetrations and the remaining tube wall thickness. There was no evidence of tube wall thinning as a result of corrosion or plastic deformation.

A corrosion crack was examined with a scanning electron microscope, supplemented with energy dispersive spectrometry for qualitative chemical analysis. Analyses of several areas around the crack tip region were completed. In general, only Ni, Cr, and Fe, typical of Alloy 600, were found. However, at one location weak indications of potassium and sulfur were present. X-ray dot mapping showed no indications of concentrations of these elements. In another area, there were weak indications of calcium, chloride, copper, magnesium, and aluminum along with silica. At no locations were there significant concentrations of chemical species that could have contributed to the failure.

The licensee concludes that the laboratory analyses confirm that outside diameter initiated intergranular stress corrosion cracking was the cause of the steam generator tube failure at Fort Calhoun. All elements for IGSCC to occur, namely: (a) susceptible material condition, (b) a significant tensile stress, and (c) an aggressive environment, were present.

Mill annealed Inconel-600 is known to be susceptible to IGSCC in caustic environments while the tensile component was imposed on the failed tube through tube-support interactions at the vertical strap locations.

The licensee speculates that periodic low-level condenser in-leakage concentrating in the steam-blanketed areas of the steam generator would produce a caustic environment in those areas. The absence of any high levels of caustic in the failed tube cracks may be the result of dissolution during plant shutdown prior to the failure.

The licensee also contends that, while normal operating stresses in straight lengths of steam generator tubes are relatively low, additional stresses may be imposed through support-tube interactions. At Fort Calhoun, there was evidence that the failed tube was constrained by the vertical support member to the extent that deformation of the tube occurred, probably as the result of corrosion product build-up between the tube and vertical support. Deformation of this type will provide additional stress at the point where failure occurred.

The licensee proposes corrective actions to reduce the probability of future tube failures. This program involves evaluating the use of boron and hydrazine pacification treatments to the secondary side to arrest denting and control of the chemical environment of the secondary side to preclude the introduction of aggressive impurities. This latter effort includes increased condenser in-leakage surveillance and condenser tube inspections and general updating of their secondary side chemistry program. Temperature soaks during heat-up to maximize impurity solubility for blowdown removal are also being considered.

3.2 Conclusions

We have concluded that the Technical Sepcification requirements for tube inspections and plugging have been met and are therefore acceptable. We accept the licensee's conclusions that the tube failure was due to outside diameter initiated stress corrosion cracking, and since there is no evidence to the contrary at this time, caustic is a reasonable first candidate as the causative agent.

The preliminary profilometry data indicates that tube ovalization/denting is occurring in those tubes at the outer areas of the tube bundle that pass through all three (3) vertical support straps, with maximum deformation occurring at the strap on the hot-leg side of the generator. This is consistent with ovalization and location of the failed tube in the generator and provides the evidence as to the source of the stress component of the observed stress corrosion cracking. The licensee's preventative plugging program included all tubes in the hot-leg vertical support region with eddy-current indications regardless of the size of the indication. There were seven (7) in this category with indications less than 20% up to 42%.

We recommend that the licensee complete the analysis of the profilometry data and reduce the tube diametric values to percent of permanent strain so that a baseline can be established for future profilometry tests. We also recommend that, unless the licensee can provide additional justification that a mid-cycle inspection is not warranted, all tubes with dent indications at the vertical support locations be examined in addition to eddy-current with profilometry nine (9) months following initial power operation (Mode 1) to measure ovality/denting so that in the event denting is not arrested we can establish a strain criteria for preventive plugging in the future. We also approve the lower primary-to-secondary leak rate limit of 0.3 gpm total for both steam generators.

A Region IV inspector observed the actual probing of the Fort Calhoun steam generator tubes on site. Additionally, the inspector reviewed the certifications for the licensee's inspection personnel who conducted the 1982 and 1984 inspections. The inspector also reviewed and confirmed the independent verification of the data gathered for each tube. We conclude that the licensee inspected the steam generator tubes using appropriate equipment, trained personnel, and that the results were independently verified.

4.0 Future Operation-Related Activities

4.1 Leakage Detection Improvements

The licensee had investigated laboratory capabilities for determining small primary-to-secondary leak rates when a small leak existed during several weeks of operation prior to the end of Cycle 8. Using typical reactor coolant boron and radionuclide concentrations and typical steam generator blowdown rates, the licensee has determined that the smallest leak rate detectable, using boron in hot shutdown, is 0.03 gpm; and using Cs-137 in hot shutdown after refueling is 0.002 gpm. Licensee Procedure CMP-4.68, Revision 0, June 12, 1984, has been issued to provide instructions to calculate the leak rate for each steam generator by gamma isotopic and boron analysis.

We have independently reviewed and verified the licensee's laboratory capabilities to determine primary-to-secondary leak rates by reproducing the licensee's leak rate equations and mathematical calculations. The results obtained were compared to those obtained using other industry accepted methods and were found acceptable. We have also verified that the licensee's calculations were based on realistic and obtainable sensitivity levels and that their analytical procedures and their gamma isotopic analysis equipment were capable of accurately detecting and identifying a small primary-to-secondary leak rate using typical reactor coolant boron and radionuclide concentrations in conjunction with typical steam generator blowdown rates. Our calculations verified that the licensee, during Mode 4 operation and continuing into Mode 1 opertion, would be able to detect a primary-to-secondary leak rate of 0.03 gpm using their approved boron analytical procedure and a leak rate of 0.002 gpm using a radionuclide measurement of typical operating fission products such as Cs-137.

We have reviewed Fort Calhoun Station Special Order No. 35, Revision 0, June 12, 1984, in which the licensee has reduced the maximum allowable primary-to-secondary leak rate through the steam generator tubes from 1 gpm total for both steam generators to 0.3 gpm. In conjunction with this, the licensee has revised ST-RLT-3, "Reactor Coolant system Leak Rate Calculation," to incorporate this additional acceptance criterion into the daily leak rate determination. Anytime an unknown leakage of ≥ 0.3 gpm is calculated, the shift chemist will be directed to perform analyses per Procedure CMP-4.68 to determine the primary-to-secondary leak rate. The licensee has committed to applying the action statement of Technical Specification 2.1.4(3) when the primary-to-secondary leak rate is found to exceed 0.3 gpm total for both steam generators.

We conclude that the licensee's method of analysis is capable of detecting primary-to-secondary leak rates significantly below the revised limit of 0.3 gpm for both steam generators, and that sufficient administrative instructions have been implemented to ensure adequate steam generator leak rate sampling and plant operational restrictions.

4.2 <u>Sampling Frequency Improvements</u>

To provide early detection of low leakage rates into the steam generators, the licensee has increased the frequency for gamma isotopic analysis of steam generator blowdown from weekly to daily. Boron analysis of steam generator blowdown will be performed once per shift beginning when the plant reaches Mode 4 and continuing until 10 days after reaching Mode 1. Steam generator blowdown monitors RM-054A and B will continue to provide continuous monitoring and automatic blowdown isolation for all but the smallest leaks.

We conclude that the licensee's sampling frequency is sufficient to ensure early detection of low leakage rates.

4.3 Procedure Reviews

OPPD Letter LIC-84-160 of May 31, 1984, from W. C. Jones to J. T. Collins, Region IV Administrator, committed the licensee to review the steam generator tube rupture emergency procedures to reconfirm their adequacy. The review team for this effort included the Reactor Engineer (SRO), a training coordinator (SRO), and two licensed operators (one SRO, one RO). This review incorporated the licensee's experience from the May 16 incident and the applicable lessons learned from the Ginna tube rupture of January 25, 1982. Guidance for the latter review was provide by NUREG 0909, "NRC Report on the January 25, 1982, Steam Generator Tube Rupture at R. E. Ginna Nuclear Power Plant," Sections 9.0 and 10.0; and NUREG 0916, "Safety Evaluation Report related to the restart of R. E. Ginna Nuclear Power Plant," Sections 1.4.1, 1.4.2, 4.2, 4.3 and 7.4. Specific items analyzed and addressed are documented in Fort Calhoun Station memorandum FC-989-84 dated June 11, 1984. On the basis of this review, the licensee found the existing procedures to be adequate, but has revised Emergency Procedures EP-30, "Steam Generator Tube Leak/Rupture (PPLS Unblocked)," Revision 28 dated June 19, 1984, and EP-30A, "Steam Genrator Tube Rupture (PPLS Blocked)," Revision 16, dated June 19, 1984, to clarify and improve the format. Other procedures reviewed included OI-RC-11, "RCS Natural Circulation Cooldown"; OP-6, Hot Standby to Cold Shutdown"; and EP-35, "Reset of Engineered Safeguards".

We have reviewed the revised emergency procedures and conclude that they provide the necessary information and guidance to enable Fort Calhoun Plant operators to take proper action in the event of a steam generator tube leak or rupture.

4.4 Licensed Operator Refresher Training

The licensee has committed to providing all licensed operator personnel with refresher training on the revised emergency procedures, EP-30 and EP-30A, prior to returning the plant to power operation. This training has commenced and will continue until all licensed personnel have been covered.

The Senior Resident Inspector (SRI) has attended one of the training sessions to ensure that the revised procedures were covered in detail, that reasons for changes were explained, and that lessons from the May 16 incident and the Ginna tube rupture incident were emphasized. THe SRI will continue to monitor this training effort to verify that all licensed personnel are trained prior to standing shift while the plant is at power operation.

We conclude that the licensee's refresher training effort is satisfactory and that, when all licensed operators have received this training, they will be adequately prepared to act properly in the event of a steam generator tube leak or rupture.

5.0 Final Conclusions

Based upon the discussions, evaluations, and conclusions above, we conclude that the Fort Calhoun Station, Unit No. 1 can safely return to power operations. We also conclude that the licensee has met the requirements of our June 5, 1984 letter. On this basis, we recommend that the licensee be authorized to return the Fort Calhoun Station, Unit No. 1 to service.

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Figure 1: Time Sequence Relating to Steam Generator Level and Pressure

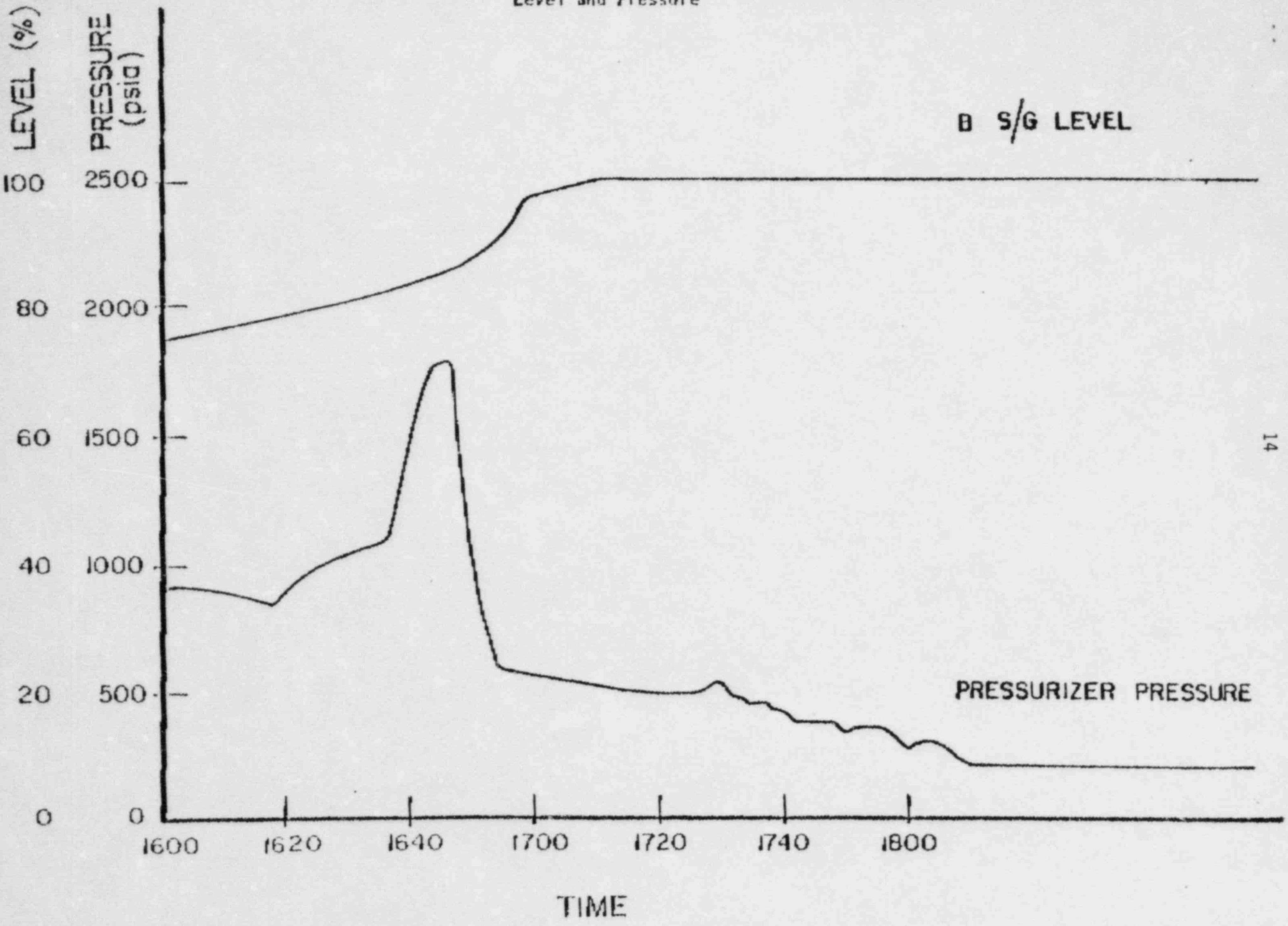

Table 1
Detailed Time History of Event
Including Initial Conditions

Initial Conditions

Plant was being taken from Mode 4 to Mode 3

RCS boron approximately 2100 ppm

T = 398F

Pressurizer level = 70%

Pressurizer pressure = 880 psia

Steam generator RC-2B level = 72%, pressure approximately 200 psig

Pressurizer fill in progress for RCS leak test; one charging pump in operation taking suction off of SIRWT

RC pumps RC-3A, RC-3B and RC-3C in operation

Letdown on minimum

Both MSIV's, HCV-1041A and HCV-1042A, open

Steam generator blowdown secured

Feeding both steam generators with FW-6 aux. feed pump; FW bypass valves HCV-1105 and HCV-1106 in AUTO

Atmospheric steam dump valve, HCV-1041, open slightly

The following is the sequence of events for the steam generator tube rupture (SGTR) of May 16, 1984.

Time	Event
1618	Operator noted that pressurizer level was no longer increasing with single charging pump in operation; pressurizer pressure decreasing slowly; started other two charging pumps.
1636	Pressurizer pressure and level slowly increasing; however, charging flow rate only aproximately 50 gpm versus expected flow rate of 120 gpm (probably due to inadequate NPSH with existing SIRWT level and three charging pumps); operator switched charging to VCT, flow rate increased to 120 gpm.

Table 1 Continued

Time	Event
1639	PPLS reset at 1700 psia (automatic).
1641	Pressurizer solid; pressurizer pressure = 1800 psia and slowly increasing
*1642	Operator isolated letdown.
	Operator noted level increasing above setpoint in RC-2B, thought to be leakage through HCV-1106, operator closed block valve HCV-1385.
1645	VCT level approaching 0% despite blended makeup in progress; operator secured two charging pumps; pressurizer pressure = 1850 psia.
1646	PPLS blocked at 1700 psia (operator action).
1648	Pressurizer pressure dropping rapidly.
*1650	Operator noted continuing increase in RC-2B level; auxiliary FW pump FW-6 secured.
1654	Pressurizer pressure = 560 psia; RCS solid; operator opened letdown valve to draw pressurizer bubble.
1658	MSIV from RC-2B, HCV-1042A, closed by operator.
1659	Cooldown of RCS initiated using steam generator RC-2A and atmospheric dump valve HCV-1040.
1700	Reactor coolant pump RC-3C secured.
1701	Reactor coolant pump RC-3B secured.
1711	Notification of unusual event declared.
1717	NRC notified via red phone.
1718	RC-2B level off-scale high; secondary pressure approximately 200 psig.
1720	Steam generator blowdown sample lined up to radioactive waste system; blowdown monitor pegged high.

Table 1 Continued

Time	Event
1730	Cooldown and depressurization of pressurizer initiated using auxiliary spray.
1830	Pressurizer pressure = 220 psia; T = 330F; pressurizer level = 70%.
1841	VCT backfilled with N_2.
2005	Shutdown cooling initiated.
(May 17, 1984)	
0005	Terminated unusual event at 210F.
*0730	Steam generator RC-2B solid.

* Time approximate based on interviews with operators; precise data unavailable.