UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

June 17, 1997

50-313

Mr. C. Randy Hutchinson
Vice President, Operations ANO
Entergy Operations, Inc.
1448 S. R. 333
Russellville, AR 72801

SUBJECT: REVIEW OF PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF OPERATIONAL EVENT AT ARKANSAS NUCLEAR ONE, UNIT 1

Dear Mr. Hutchinson:

Enclosed for your review and comment is a copy of the preliminary Accident Sequence Precursor (ASP) analysis of an operational event which occurred at Arkansas Nuclear One, Unit 1, on May 19, 1996 (Enclosure 1), and was reported in Licensee Event Report (LER) No. 313/96-005. This analysis was prepared by our contractor at the Oak Ridge National Laboratory (ORNL). The results of this preliminary analysis indicate that this event may be a precursor for 1996. In assessing operational events, an effort was made to make the ASP models as realistic as possible regarding the specific features and response of a given plant to various accident sequence initiators. We realize that licensees may have additional systems and emergency procedures, or other features at their plants that might affect the analysis. Therefore, we are providing you an opportunity to review and comment on the technical adequacy of the preliminary ASP analysis, including the depiction of plant equipment and equipment capabilities. Upon receipt and evaluation of your comments, we will revise the conditional core damage probability calculations where necessary to consider the specific information you have provided. The object of the review process is to provide as realistic an analysis of the significance of the event as possible.

In order for us to incorporate your comments, perform any required reanalysis, and prepare the final report of our analysis of this event in a timely manner, you are requested to complete your review and to provide any comments within 30 days of receipt of this letter. We have streamlined the ASP Program with the objective of significantly improving the time after an event in which the final precursor analysis of the event is made publicly available. As soon as our final analysis of the event has been completed, we will provide for your information the final precursor analysis of the event and the resolution of your comments. In previous years, licensees have had to wait until publication of the Annual Precursor Report (in some cases, up to 23 months after an event) for the final precursor analysis of an event and the resolution of their comments.

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We have also enclosed several items to facilitate your review. Enclosure 2 contains specific guidance for performing the requested review, identifies the criteria which we will apply to determine whether any credit should be given in the analysis for the use of licensee-identified additional equipment or

specific actions in recovering from the event, and describes the specific information that you should provide to support such a claim. Enclosure 3 is a copy of LER No. 313/96-005, which documented the event.

Please contact me at 301-415-1308 if you have any questions regarding this request. This request is covered by the existing OMB clearance number (3150-0104) for NRC staff followup review of events documented in LERs. Your response to this request is voluntary and does not constitute a licensing requirement.

Sincerely,

George Kalman

George Kalman, Senior Project Manager
Project Directorate IV-1
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket No. 50-313

Enclosures: 1. ASP Analysis
2. Guidance for Lic. Review
3. LER No. 313/96-005

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Sincerely,

Orig. signed by
George Kalman, Senior Project Manager
Project Directorate IV-1
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket No. 50-313

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LER No. 313/96-005

Event Description: Reactor Trip and Subsequent Steam Generator Dryout

Date of Event: May 19, 1996

Plant: Arkansas Nuclear One, Unit 1

Summary

Arkansas Nuclear One, Unit 1 (ANO 1) was operating at 100% power when the plant experienced an automatic trip on high reactor coolant system (RCS) pressure that resulted from reduced main feedwater (MFW) flow. Following the scram, six of eight Main Steam Safety Valves (MSSVs) lifted on the B Once Through Steam Generator (OTSG). One of these safety valves stuck open when pressure was reduced, and about 18 min after the trip, the operators, in accordance with the plant emergency operating procedures, isolated the faulted B OTSG from its MFW source and its steam outlet. With the pressure and temperature decreasing on the secondary side of the OTSG, the OTSG was allowed to "dry out" because the RCS temperature was maintained relatively constant. About 5 h and 41 min after the trip, the stuck-open safety valve was gagged closed. After that, the B OTSG was refilled and the plant was returned to normal hot shutdown conditions. The estimated conditional core damage probability (CCDP) for this event is 1.1×10^{-5}.

Event Description

According to the licensee event report (LER) (Ref. 1), the plant was operating at 100% power when a degradation of the power supply to the turbine hydraulic control valve for MFW pump (MFWP) A caused a rapid decrease in pump speed. A second decrease in pump speed resulted in the pump going to minimum speed. The Integrated Control System (ICS) responded to the change in feedwater flow by increasing the speed on MFWP B. The lower heat-removal rate resulting from the reduced feedwater flow caused by MFWP A going to minimum speed in turn caused the pressure in the reactor to increase. The increasing pressure, in turn, caused the reactor to automatically trip on high pressure, just before the operators attempted to manually trip the reactor. At this time, MFWP A was at minimum speed, the feedwater cross-over valve was closed (normal position) because no MFWP trip signal was present, and MFWP B was at maximum speed and in its "Diagnostic-Manual" mode and not responding to additional ICS signals. Following the trip, A OTSG had a low water level inventory and B OTSG a high water level inventory. However, because of a back pressure wave induced by closing the main turbine stop valves, the sensed water level in the B OTSG indicated low, thereby actuating the Emergency Feedwater (EFW) system. MFWP B tripped on high discharge pressure approximately 14 s after the reactor scram and MFWP A responded to ICS demand signals when its control circuit fault cleared; however, because the demand signal was very high, MFWP A tripped on mechanical overspeed about 37 s after the reactor trip.

Secondary side steam pressure in the A OTSG remained below the MSSV setpoints because of the reduced inventory in the steam generator that resulted from the lower feedwater flow rate due to the MFWP A speed

ENCLOSURE 1

decrease; conversely, the high inventory in the B OTSG (caused by MFWP B going to maximum speed) resulted in a high secondary side steam pressure. Consequently, six of the eight MSSVs on the B OTSG opened to reduce pressure. These valves opened prior to the A and B MFW pump trips. The operators noted approximately 64 s after the reactor trip that one of the MSSVs had failed to reclose following the pressure reduction, thus causing an accelerated RCS cooldown rate. Operators manually initiated high pressure injection (HPI) about six min after the reactor trip in accordance with the plant's Emergency Operating Procedures (EOPs) when the water level in pressurizer dropped below 30 in. Following that, also in accordance with EOPs, the faulted OTSG (B) was isolated from its feedwater source and steam outlet about 18 min after the trip. The secondary side of the OTSG continued to "blow down" through the open MSSV; however, the operators controlled the RCS cooldown rate by maintaining the RCS temperature above 520°F. This blowdown is also referred to as "drying out" the OTSG, and the lack of steam in the OTSG results in the OTSG shell cooling down below the RCS temperature (Ref. 2). This tube-to-shell temperature differential is governed by Plant Technical Specifications and is limited to 60°F for ANO 1. During this transient, however, the shell-to-tube temperature differential increased to 74°F. The vendor, Framatome Technology, Inc., and the licensee both analyzed the 74°F temperature difference and concluded no excessive stresses were induced on the OTSG or the reactor pressure vessel.

With the steam header B isolated, the normal supply for sealing steam for the gland seals on the main turbine was not available, and because the backup steam supply (the auxiliary boiler) was also unavailable due to control system problems, sealing steam was eventually lost. As a result, about 35 min after the trip, the vacuum in the main condenser was lost. However, heat removal was still possible after the main condenser became unavailable by discharging steam through an atmospheric dump valve, which the operators did until the auxiliary boiler was available. At this time, the vacuum in the main condenser was reestablished and the main condenser was again used for heat removal.

Plant maintenance crews successfully gagged closed the MSSV approximately 5 h and 41 min after the reactor trip. Using EFW, operators then began refilling B OTSG and cleared the main steam line isolation signal. The main steam isolation valve for B OTSG was opened about 2 h later and the main feedwater isolation valve about an hour after that. At that time, normal feedwater was established to the OTSG and the plant was restored to a normal hot shutdown condition.

Additional Event-Related Information

A short circuit in a digital speed sensing probe for MFWP A reduced voltage in the feedwater control system 24 volt power supply. This, in turn, decreased control oil pressure for the MFWP turbine steam admission valve, causing the valve to partially close. The closing of the steam admission valve decreased the speed of MFWP A, thereby decreasing feedwater flow. The reduced feedwater flow in turn caused the ICS to demand maximum MFW; however, the MFW control system incorrectly interpreted this as a failure (invalid signal) in the ICS, and transferred MFWP B control to the "Diagnostic Manual" mode. This effectively kept MFWP B operating in response to the last valid sensed signal (high demand). When the reactor tripped, [illegible] sent a reduction signal to the feedwater control system. However, MFWP B did not respond since it was in "Diagnostic Manual." The feedwater block valves closed in response to the rapid flow reduction signal. As a result, the system pressure increased rapidly, and MFWP B tripped on overpressure.

The MFW system at ANO 1 consists of two variable-speed turbine-driven pumps which take their common suction downstream of feedwater heaters E2A and E2B and discharge to the OTSGs. Either MFWP can discharge to both OTSGs by routing through the normally closed feedwater cross-over valve located before the feedwater flow control valves (Ref. 3, 4). Typically, these pumps are used to supply feedwater to the OTSGs from about 3% power to full power. The system also has an auxiliary motor-driven pump. This pump is used to supply feedwater to the OTSGs during plant startup and shutdown below 3% power. The auxiliary pump takes a suction from the MFWP suction header and discharges to the MFWP A discharge header upstream of the cross-over valve. The MFWPs are rated at 60% full-load capacity each and the auxiliary feedwater pump is rated at 5% full-load capacity.

The MSSV that did not reclose failed to reseat because the locking device cotter pin was not engaged with the release nut. This allowed the release nut to travel down the spindle of the valve and block the manual lift top lever from returning to its normal position. This phenomenon has been documented in an NRC Information Notice 84-33, as well as in other industry studies. Investigations indicate that either the failure of the cotter pin or the insufficient slot engagement by the cotter pin allows the release nut to rotate down the spindle while the MSSV is lifted. The NRC Augmented Inspection Team (in Sections 3.2 and 6.3 of Ref. 2) sent to investigate this event found that of the 16 MSSVs on ANO 1:

> one stuck-open, . . . because of a stem-nut utilized to facilitate manual lifting of the valve, not being properly pinned in place so that during lift and/or blowdown of the valve the nut traveled down the stem and contacted the lifting device. This contact precluded the valve from reseating.;
>
> . . . 6 of the 15 other MSSVs in Unit 1 had less than desirable cotter pin engagement . . .;
>
> 2 of the remaining 9 had marginal (i.e., cotter pin) engagement. (i.e., and the remaining 7 valves had acceptable cotter pin engagement);
>
> . . . despite marginal engagement, none of the nuts could be rotated by hand.

Hence, the above shows that preventing the release nut from rotating could prevent the valve from reclosing after it had opened. The NRC's Augmented Inspection Team determined that the licensee's procedures for installing the cotter pins were inadequate. Moreover, the licensee in their own inspection (Ref. 1, Section D) found that:

> Cotter pins for two other valves were found not engaged in the release nuts. These valves were determined to have been operable since the release nuts could not be rotated due to the cotter pin ends being engaged on the nuts. Six valves had the pins partially engaged at the top end of the release nut slot. Seven valves were found with the cotter pins fully engaged.

Based on the above, it was determined that this was a singular incident.

Modeling Assumptions

This event was examined as the combination of two individual events. The first is the reactor trip and subsequent loss of main feedwater transient (LOFW). The second is the potential for a steam generator tube rupture (SGTR) as a result of the "drying out" of B OTSG. The LOFW is a relatively simple and straightforward transient with few complications other than operator burdens in the recovery process. The potential for a SGTR, however, is neither simple nor straightforward. Both are discussed below.

LOFW

The LOFW transient began with the reactor trip, continued through the subsequent OTSG dryout, and concluded with MFW recovery. The transient concluded when the main feedwater isolation valve was opened which, according to Ref. 2, Attachment 1, was approximately 9 h and 36 min after the trip. The event was modeled as a high pressure reactor trip initiating event with subsequent LOFW (IE-TRANS and MFW-SYS-TRIP set to TRUE for this portion of the analysis). MFW was assumed recoverable; however, it should be noted that both MFWPs were tripped (one on mechanical overspeed and the other had tripped on high discharge pressure, but also had an undetermined failure in its control system) and were not used in lieu of EFW prior to the OTSG isolation. After that, in the long-term after the OTSG isolation, EFW was also used to supply the on-line OTSG. When the isolation was cleared, the B OTSG was refilled using EFW. MFW was not used until the OTSGs were supplied via the startup valves about 9 h and 42 min after the trip (Ref. 2, Attachment 1), and EFW was not secured until almost 10 h after the reactor trip (Ref. 2, Attachment 1). The ANO 1 model used in conjunction with the Integrated Reliability and Risk Analysis System (IRRAS) (Ref. 5) already includes the motor-driven auxiliary feedwater pump as a supplement to the MFW when the MFWPs have tripped-off or have failed.

SGTR

The typical accident analysis for core damage examines loss of coolant accidents (LOCAs), of which the small-break LOCA (SLOCA) is a subset. The SGTR, in many aspects, is similar to the SLOCA. The SGTR is examined for its resulting affect on core integrity. According to NUREG-0844 (Ref. 6):

> . . . concerns which were raised relative to steam generator tube degradation stem from the fact that the steam generator tubes are a part of the reactor coolant system (RCS) bounda.. / and that tube failures result in a loss of primary coolant. . . .
>
> The leakage of primary coolant into the secondary has two major safety implications. The first is the potential for direct release of radioactive fission products into the environment, and the second is the loss of cooling water which is needed to prevent core damage. An extended uncontrolled loss of coolant outside containment would result in the depletion of the initial RCS inventory and emergency core cooling system (ECCS) water without the capability to recirculate the water.

The licensee and the Framatome Technologies, Inc. examined this event by focusing on the differential temperature (Δt) experienced by the OTSG during the dryout, and they correlated that temperature to a pounds compressive force (Ref. 2, Section 4.2). The maximum Δt occurred approximat^ly 2 h and 44 min

after the trip (Ref. 2, Attachment 1). The stresses induced by the corresponding high Δt during the OTSG dryout were probably greater than those produced by the transient induced differential pressure (Δp); however, if the scope of the analysis follows the increased stress due to the maximum Δt, the underlying assumption still concerns tube integrity, and the analysis will ultimately result in examination of tube rupture or leakage. The analysis will follow the SGTR after that. NUREG-0844 correlates the transient-induced Δp with the probability for tube rupture. Therefore, in the absence of a simple correlation available to reconcile the stresses induced by the temperature increase, the transient was analyzed using the Δp increase rather than the Δt increase.

About 18 min after the plant had shut down, the OTSG was isolated and allowed to blow down through the stuck-open MSSV. While the secondary side pressure was decreasing, the primary side (RCS pressure) was kept nearly constant (Ref. 2, 4). This resulted in the OTSG tubes being exposed to an increasing Δp which stopped increasing only when the safety valve was gagged closed. The OTSG secondary side pressure decreased to 20 psig (Ref. 7), while the primary side pressure was stabilized near the normal operating pressure (Ref. 2, 7) of 2155 psig (Ref. 4). This means the tubes of the B OTSG were subjected to a maximum Δp of 2135 psid. NUREG-0844 (Ref. 6) assesses the probability of SGTR given a transient-induced Δp on the OTSG tubes. Section 3.1.2.1 of NUREG-0844 (Ref. 6) indicates that the conditional probability for one or more tube ruptures on a steam generator during a transient may be calculated by the following equation.

$$C_i = C_s \left[(\Delta P_i - \Delta P_n) / (\Delta P_s - \Delta P_n) \right]^2$$

Where: C_i is the conditional probability for one or more tube ruptures during transient "I"

C_s is the conditional probability for one or more tube ruptures during a postulated main steam line break (MSLB) accident

ΔP_i is the peak differential pressure across the tubes during transient "I"

ΔP_n is the normal operating pressure differential across the tubes

ΔP_s is the peak differential pressure across the tube during a postulated MSLB accident.

For this event: C_a = 0.05 (Ref. 6)[a], ΔP_i = 2135 psid (Ref. 2, 4, 7)[b], ΔP_n = 1245 psid (Ref. 4)[c], and ΔP_a = 2600 psid (Ref. 6).

When these values are inserted into the equation, $C_i = (0.05)\,(890/1355)^2 = 0.0216$. For this portion of the analysis, IE-SGTR was set to TRUE. Further, it should be noted that according to Ref. 3 (Section 3.1.2.5), following the failure of HPI during an SGTR, the operators have about 30 min to lower the RCS pressure below the MSSV setpoints before core damage results. Therefore, this recovery action was modeled by adding a basic event, RCS-XHE-DEP-HPI, to the IRRAS model for ANO 1. Based on the operator burden given the time constraint of 30 min, a failure probability of 0.1 was assigned to RCS-XHE-DEP-HPI.

EVENT MODEL

The analyses for LOFW and SGTR were combined to analyze the entire event as follows:

[P(SGTR) × estimated CCDP for SGTR] + [[1 - P(SGTR)] × estimated CCDP for LOFW]]

Analysis Results

The estimated CCDP for this event is 1.1×10^{-5}. This estimation was derived from the equation mentioned in the previous section and is calculated as follows:

[P(SGTR) × estimated CCDP for SGTR] + [[1 - P(SGTR)] × estimated CCDP for LOFW]]

where:

probability of tube rupture	=	0.0216
1-probability of tube rupture	=	0.9784
CCDP due to SGTR	=	4.61×10^{-4}
CCDP due to LOFW	=	6.37×10^{-7}

[a] From Section 3.1.2.1 of Ref. 6, "...the staff has assumed an overall conditional probability of 0.05 that one or more tubes will be vulnerable to rupture during postulated accident conditions."

[b] From Section 4.2 of Ref. 2, "The primary system pressure and temperature stabilized near the normal operating range..." From Ref. 7, "the minimum shell pressure recorded was ~ 20 psig . . ." Normal operating pressure is 2155 psig according to Section 4.3.1 of Ref. 4. Therefore, ΔP_i = 2155 psig - 20 psig = 2135 psid.

[c] Section 10.3 of Ref. 4 indicates that the normal OTSG outlet pressure at 100% power is 910 psig and Section 4.3.1 indicates normal RCS operating pressure is 2155 psig. Therefore, ΔP_n = 2155 psig - 910 psig = 1245 psid.

The dominant core damage sequence, highlighted as sequence number 9 on Figure 1, contributes approximately 89% to the estimated CCDP for SGTR. The dominant sequence involves

- SGTR initiating event occurs,
- the reactor is successfully tripped,
- EFW is successful,
- HPI is successful,
- the operators fail to depressurize the RCS below the MSSV setpoint[d],

Interestingly, the LOFW contributes less than 6% to the estimated total CCDP.

Definitions and probabilities for selected basic events are shown in Table 1. The conditional probabilities and sequence logic associated with the highest probability sequences are shown in Table 2. Table 3 describes system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table 4. Since the LOFW transient contributed less than 6% to the total CCDP, information regarding the analysis was not included in Tables 1 through 4.

Acronyms

ANO 1	Arkansas Nuclear One, Unit 1
CCDP	conditional core damage probability
ECCS	emergency core cooling system
EOP	emergency operating procedures
EFW	emergency feedwater
HPI	high pressure injection
ICS	integrated control circuit
IRRAS	integrated reliability and risk analysis system
LER	licensee event report
LOCA	loss of coolant accident
LOFW	loss of feedwater
MFW	main feedwater
MFWP	main feedwater pump
MSLB	main steam line break
MSSV	main steam safety valves
OTSG	once through steam generator
PORV	power-operated relief valve
RCS	reactor coolant system
SGTR	steam generator tube rupture
SLOCA	small-break loss of coolant accident

[d]This includes hardware failures causing the failure to depressurize and operator failure to initiate RCS depressurization.

References

1. LER 313/96-005, Rev. 0, "Automatic Reactor Trip and Engineered Safety Features Actuations Caused by Failure of a Speed Sensing Probe in the Control Circuitry of a Main Feedwater Pump Turbine and Failure of a Main Steam Safety Valve to Re-Seat," June 18, 1996.

2. NRC Augmented Inspection Team Report No. 50-313, -368/96-19, June 12, 1996.

3. *ANO 1 Probabilistic Risk Assessment - Individual Plant Examination Submittal*, April 1993.

4. *ANO 1 Safety Analysis Report, Amendment 13*, September 25, 1995.

5. U.S. Nuclear Regulatory Commission, "Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE), Version 5.0," NUREG/CR-6116 (EGG-2716), Volumes 1-10, July 1994.

6. U.S. Nuclear Regulatory Commission, "NRC Integrated Program of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," NUREG-0844, September 1988.

7. Personal communication, P. D. O'Reilly, U.S. NRC with T. Reis, U.S. NRC.

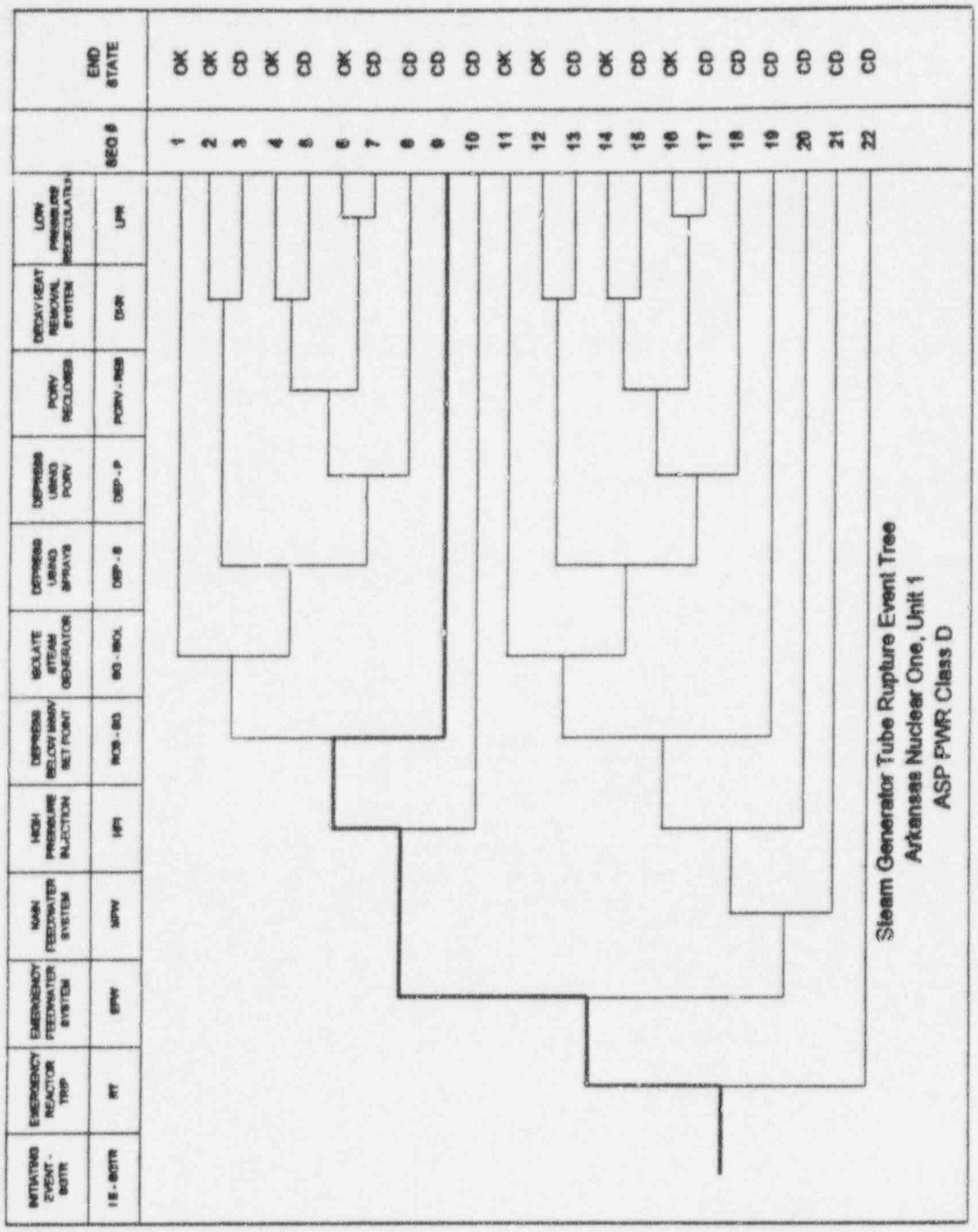

Fig. 1 Dominant core damage sequence for LER 313/96-005.

Table 1. Definitions and Probabilities for Selected Basic Events for LER No. 313/96-005

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-SGTR	Steam Generator Tube Rupture Initiating Event	1.6×10^{-6}	$1.0 \times 10^{+0}$	TRUE	Yes
HPI-CKV-OO-MST	Makeup Storage Tank Stop Check Valve Fails to Seat	3.0×10^{-3}	3.0×10^{-3}		No
HPI-MDP-CF-ABC	High Pressure Injection (HPI) Motor-Driven Pumps Fail to Run due to Common Cause	1.2×10^{-5}	1.2×10^{-5}		No
HPI-MDP-FC-1C	HPI Train C Fails	3.9×10^{-3}	3.9×10^{-3}		No
HPI-MOV-CC-SUCA	Train A Suction Isolation Motor-Operated Valve Fails	3.1×10^{-3}	3.1 × 10[illegible]		No
HPI-MOV-CC-SUCC	Train C Suction Isolation Motor-Operated Valve Fails	3.1×10^{-3}	3.1×10^{-3}		No
HPI-MOV-CF-SUCT	HPI Suction Isolation Motor-Operated Valves Fail due to Common Cause	2.6×10^{-4}	2.6×10^{-4}		No
HPI-XHE-NOREC1	Operator Fails to Restore HPI System After Failure	8.4×10^{-1}	8.4×10^{-1}		No
PCS-PSF-HW	Hardware Failures Causing Failure to Depressurize	1.0×10^{-5}	1.0×10^{-5}		No
PCS-XHE-XM-SG	Operator Fails to Initiate RCS Depressurization	4.0×10^{-4}	4.0×10^{-4}		No
RCS-XHE-DEP-HPI	Operator Fails to Depressurize the RCS Within 30 Min After HPI Failure	1.0×10^{-1}	1.0×10^{-1}	NEW	Yes
RPS-NONREC	Non-recoverable RPS Failures	2.0×10^{-5}	2.0×10^{-5}		No
RPS-REC	Recoverable RPS Failures	4.0×10^{-5}	4.0×10^{-5}		No
RPS-XHE-XM-SCRAM	Operator Fails to Manually Trip the Reactor	1.0×10^{-2}	1.0×10^{-2}		No

Table 2. Sequence Conditional Probabilities for LER No. 313/96-005

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution[a]	Logic
SGTR	9	4.1×10^{-4}	88.9	/RT, /EFW, /HPI, RCS-SG
SGTR	10	2.8×10^{-5}	5.9	/RT, /EFW, HPI
SGTR	22	2.0×10^{-5}	4.4	RT
Subtotal (SGTR)		**4.6×10^{-4}**		

[a] Percent contribution to the subtotal CCDP

Table 3. System Names for LER No. 313/96-005

System name	Description
EFW	No or Insufficient Emergency Feedwater (EFW) System Flow
HPI	No or Insufficient Flow From the High Pressure Injection (HPI) System
RCS-SG	Failure to Lower RCS Pressure to < OTSG Relief Valve (MSSV) Setpoint
RT	Reactor Fails to Trip During Transient

Table 4. Conditional Cut Sets for Higher Probability Sequences for LER No. 313/96-005

Cut set number	Percent contribution	Conditional probability[a]	Cut sets
SGTR Sequence 9		4.1×10^{-4}	
1	97.5	4.0×10^{-4}	PCS-XHE-XM-SG
2	2.4	1.0×10^{-5}	PCS-PSF-HW
SGTR Sequence 10		2.7×10^{-5}	
1	80.2	2.2×10^{-5}	HPI-MOV-CF-SUCT, HPI-XHE-NOREC1, RCS-XHE-DEP-HPI
2	3.7	1.0×10^{-6}	HPI-MDP-CF-ABC, HPI-XHE-NOREC1, RCS-XHE-DEP-HPI
3	3.6	1.0×10^{-6}	HPI-MOV-CC-SUCA, HPI-MDP-FC-1C, HPI-XHE-NOREC1, RCS-XHE-DEP-HPI
4	3.5	9.8×10^{-7}	HPI-CKV-OO-MST, HPI-MDP-FC-1C, HPI-XHE-NOREC1, RCS-XHE-DEP-HPI
5	2.9	8.1×10^{-7}	HPI-MOV-CC-SUCA, HPI-MOV-CC-SUCC, HPI-XHE-NOREC1, RCS-XHE-DEP-HPI
6	2.8	7.8×10^{-7}	HPI-CKV-OO-MST, HPI-MOV-CC-SUCC, HPI-XHE-NOREC1, RCS-XHE-DEP-HPI
SGTR Sequence 22		2.0×10^{-5}	
1	98.0	2.0×10^{-5}	RPS-NONREC
2	1.9	4.0×10^{-7}	RPS-XHE-XM-SCRAM, RPS-REC

[a]The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cutset. The probabilities of the initiating and basic events are given in Table 1. Initiating events begin with the designator, IE.

GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS

Background

The preliminary precursor analysis of an operational event that occurred at your plant has been provided for your review. This analysis was performed as a part of the NRC's Accident Sequence Precursor (ASP) Program. The ASP Program uses probabilistic risk assessment techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include actual initiating events, such as a loss of off-site power (LOOP) or loss-of-coolant accident (LOCA), degradation of plant conditions, and safety equipment failures or unavailabilities that could increase the probability of core damage from postulated accident sequences. This preliminary analysis was conducted using the information contained in the plant-specific final safety analysis report (FSAR), individual plant examination (IPE), and the licensee event report (LER) for this event.

Modeling Techniques

The models used for the analysis of 1995 and 1996 events were developed by the Idaho National Engineering Laboratory (INEL). The models were developed using the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) software. The models are based on linked fault trees. Four types of initiating events are considered: (1) transients, (2) loss-of-coolant accidents (LOCAs), (3) losses of offsite power (LOOPs), and (4) steam generator tube ruptures (PWR only). Fault trees were developed for each top event on the event trees to a supercomponent level of detail. The only support system currently modeled is the electric power system.

The models may be modified to include additional detail for the systems/components of interest for a particular event. This may include additional equipment or mitigation strategies as outlined in the FSAR or IPE. Probabilities are modified to reflect the particular circumstances of the event being analyzed.

Guidance for Peer Review

Comments regarding the analysis should address:

- Does the "Event Description" section accurately describe the event as it occurred?

- Does the "Additional Event-Related Information" section provide accurate additional information concerning the configuration of the plant and the operation of and procedures associated with relevant systems?

- Does the "Modeling Assumptions" section accurately describe the modeling done for the event? Is the modeling of the event appropriate for the events that occurred or that had the potential to occur under the event conditions? This also includes assumptions regarding the likelihood of equipment recovery.

Appendix H of Reference 1 provides examples of comments and responses for previous ASP analyses.

Criteria for Evaluating Comments

Modifications to the event analysis may be made based on the comments that you provide. Specific documentation will be required to consider modifications to the event analysis. References should be made to portions of the LER, AIT, or other event documentation concerning the sequence of events. System and component capabilities should be supported by references to the FSAR, IPE, plant procedures, or analyses. Comments related to operator response times and capabilities should reference plant procedures, the FSAR, the IPE, or applicable operator response models. Assumptions used in determining failure probabilities should be clearly stated.

Criteria for Evaluating Additional Recovery Measures

Additional systems, equipment, or specific recovery actions may be considered for incorporation into the analysis. However, to assess the viability and effectiveness of the equipment and methods, the appropriate documentation must be included in your response. This includes:

- normal or emergency operating procedures.*
- piping and instrumentation diagrams (P&IDs),*
- electrical one-line diagrams,*
- results of thermal-hydraulic analyses, and
- operator training (both procedures and simulator),* etc.

Systems, equipment, or specific recovery actions that were not in place at the time of the event will not be considered. Also, the documentation should address the impact (both positive and negative) of the use of the specific recovery measure on:

- the sequence of events,
- the timing of events,
- the probability of operator error in using the system or equipment, and
- other systems/processes already modeled in the analysis (including operator actions).

For example, Plant A (a PWR) experiences a reactor trip, and during the subsequent recovery, it is discovered that one train of the auxiliary feedwater (AFW) system is unavailable. Absent any further information regrading this event, the ASP Program would analyze it as a reactor trip with one train of AFW unavailable. The AFW modeling would be patterned after information gathered either from the plant FSAR or the IPE. However, if information is received about the use of an additional system (such as a standby steam generator feedwater system) in recovering from this event, the transient would be modeled as a reactor trip with one train of AFW unavailable, but this unavailability would be

* Revision or practices at the time the event occurred.

mitigated by the use of the standby feedwater system. The mitigation effect for the standby feedwater system would be credited in the analysis provided that the following material was available:

- standby feedwater system characteristics are documented in the FSAR or accounted for in the IPE,
- procedures for using the system during recovery existed at the time of the event,
- the plant operators had been trained in the use of the system prior to the event,
- a clear diagram of the system is available (either in the FSAR, IPE, or supplied by the licensee),
- previous analyses have indicated that there would be sufficient time available to implement the procedure successfully under the circumstances of the event under analysis,
- the effects of using the standby feedwater system on the operation and recovery of systems or procedures that are already included in the event modeling. In this case, use of the standby feedwater system may reduce the likelihood of recovering failed AFW equipment or initiating feed-and-bleed due to time and personnel constraints.

Materials Provided for Review

The following materials have been provided in the package to facilitate your review of the preliminary analysis of the operational event.

- The specific LER, augmented inspection team (AIT) report, or other pertinent reports.

- A summary of the calculation results. An event tree with the dominant sequence(s) highlighted. Four tables in the analysis indicate: (1) a summary of the relevant basic events, including modifications to the probabilities to reflect the circumstances of the event, (2) the dominant core damage sequences, (3) the system names for the systems cited in the dominant core damage sequences, and (4) cut sets for the dominant core damage sequences.

Schedule

Please refer to the transmittal letter for schedules and procedures for submitting your comments.

References

1. L. N. Vanden Heuvel et al., Precursors to Potential Severe Core Damage Accidents: 1994, A Status Report, USNRC Report NUREG/CR-4674 (ORNL/NOAC-232) Volumes 21 and 22, Martin Marietta Energy Systems, Inc., Oak Ridge National Laboratory and Science Applications International Corp., December 1995.

ENTERGY

Entergy Operations, Inc.

June 18, 1996

1CAN069603

U. S. Nuclear Regulatory Commission
Document Control Desk
Mail Station P1-137
Washington, DC 20555

Subject: Arkansas Nuclear One - Unit 1
Docket No. 50-313
License No. DPR-51
Licensee Event Report 50-313/96-005-00

Gentlemen:

In accordance with 10CFR50.73(a)(2)(iv), enclosed is the subject report concerning an automatic reactor trip.

Very truly yours,

Dwight C. Mims

Dwight C. Mims
Director, Nuclear Safety

DCM/tfs

enclosure

200032

ENCLOSURE 3

IE22

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NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Arkansas Nuclear One - Unit 1	05000313	1 OF 7

TITLE (4) AUTOMATIC REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATIONS CAUSED BY FAILURE OF A SPEED SENSING PROBE IN THE CONTROL CIRCUITRY OF A MAIN FEED WATER PUMP TURBINE AND FAILURE OF A MAIN STEAM SAFETY VALVE TO RE-SEAT

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
05	19	96	96	005	00	06	18	96	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (Check one or more) (11)						
			20.[illegible]		20.405(c)	X	50.73(a)(2)(iv)	70.73(b)
POWER LEVEL (10)	100		20.[illegible](1)(i)		50.36(c)(1)		50.73(a)(2)(v)	70.73(c)
			20.[illegible](a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)	OTHER
			20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)	Specify in
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)	Abstract Below
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)	and in Text

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Thomas F. Scott, Nuclear Safety and Licensing Specialist	501-858-4623

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	JK	ST	L253	Y						
A	SB	RV	D243	Y						

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

ANO-1 experienced a reactor trip on high Reactor Coolant System (RCS) pressure. The pressure increase was caused by reduced Main Feed Water (MFW) flow originating from a component failure affecting controls of one of the operating MFW pumps. After the reactor trip, the other MFW pump tripped on high discharge pressure. Emergency Feed Water (EFW) automatically actuated. As expected, several Main Steam Safety Valves (MSSVs) opened following the reactor trip. One MSSV failed to re-seat. This led to the manual start of one High Pressure Injection pump because of reduced pressurizer level and manual actuation of Main Steam Line Isolation of the affected Once Through Steam Generator (OTSG). The MSSV failed to re-seat because inadequate engagement between the valve release nut and a cotter pin used to lock it in place allowed the nut to rotate and engage the manual lift top lever. Secondary water inventory of the affected OTSG was depleted via the open MSSV. Isolation of the OTSG, which provides the primary source of main turbine gland sealing steam, caused degradation of main condenser vacuum. RCS temperature control was maintained by the Atmospheric Dump System on the other OTSG. The open MSSV was gagged shut. Water inventory was restored by EFW. The first MFW pump control anomaly was caused by a drop in power supply voltage due to a shorted speed sensor. The failed speed sensor was replaced. Modifications wer made to fuse the speed sensors and correct the cause of the second MFW pump trip. A modification was made to the MSSVs (other than the one gagged) to minimize the possibility of future inadequate pin engagement.

NRC FORM 366A (5-92)

A. Plant Status

At the time of this event, Arkansas Nuclear One Unit 1 (ANO-1) was operating in steady-state conditions at approximately 100 percent power with Reactor Coolant System (RCS) [AB] average temperature approximately 579 degrees.

B. Event Description

An automatic reactor trip on high RCS pressure occurred at 0312 hours on May 19, 1996, due to a reduction in Main Feed Water (MFW) [SJ] flow.

At approximately 0311 hours, control oil pressure for the "A" Main Feed Water Pump (MFWP) turbine decreased causing pump speed and feed water flow to decrease. The feed water cross-over valve remained in its normal closed position because no MFWP trip signal was present. The reduction in flow caused the Integrated Control System (ICS) [JA] to demand maximum flow from both MFW loops. The ICS maximum demand signal was incorrectly interpreted as failed by the MFWP control system. This caused "B" MFWP controls to shift to the "Diagnostic-Manual" mode. While in this mode, the MFWP control system is being directed by what it considers the last valid signal and does not respond to additional ICS signals. The controls for "B" MFWP remained in "Diagnostic-Manual" and maintained the pump at its maximum speed. RCS pressure began increasing due to the decreased heat removal from degraded "A" MFWP flow. The Control Room Operator observed the increasing RCS pressure and attempted to manually trip the reactor. The manual trip was sensed 0.2 seconds following an automatic trip on high RCS pressure at 0312, less than one minute after the condition was initiated. All control rods inserted with acceptable insertion times.

Approximately four seconds after the trip, Emergency Feed Water (EFW) [BA] actuated on a sensed low water level in "B" Once Through Steam Generator (OTSG) [AB]. The "B" MFWP, which was holding at full speed in the "Diagnostic-Manual" mode, tripped on high discharge pressure approximately 14 seconds after the reactor trip when its associated MFW block valve closed as designed in response to the reactor trip. The fault in the "A" MFWP control system cleared and the pump controls attempted to respond to the high demand signals being generated by the ICS. As a result, the "A" MFWP turbine tripped on mechanical over speed approximately 37 seconds after the reactor trip. OTSG inventory was subsequently maintained by EFW with both trains functioning properly.

Pressure in "A" OTSG did not reach the setpoints of the Main Steam Safety Valves (MSSVs) [SB] because of the reduced water inventory as a result of the initiating control problems of "A" MFWP. Steam pressure in "B" OTSG was sufficient to cause six of the eight MSSVs to open. MSSVs lifting

following a reactor trip is an expected response for ANO-1. One of these valves, PSV-2685, failed to re-seat. This caused an accelerated cooldown of the RCS. When pressurizer level fell below 30 inches, one High Pressure Injection (HPI) [BQ] pump was manually started in accordance with Emergency Operating Procedure (EOP) guidance at 0318 hours to assist the running Make Up (MU) [CB] pump in maintaining RCS inventory. The minimum pressurizer level of 12 inches occurred at 0319. The HPI pump was stopped at 0327.

At 0328, after trying unsuccessfully to re-seat the MSSV, Operators manually initiated Main Steam Line Isolation (MSLI) [JB] of "B" OTSG to stop the cool down transient. Both actions, attempting to re-seat the MSSV and isolation of the OTSG, were performed using EOP guidance. At 0330, a Notification of Unusual Event (NUE) was declared based upon the uncontrolled depressurization of "B" OTSG and its EFW supply was manually isolated. The secondary side of "B" OTSG began to dry via the open MSSV. During the blow down, the RCS cool down rate remained within analysis and Technical Specification limits. RCS average temperature remained above 520 degrees. Because of the lack of steam in "B" OTSG, the shell cooled to approximately 74 degrees below RCS temperature. This exceeded the tube-to-shell temperature difference (tubes hotter) of 60 degrees recommended by the vendor. Both of these conditions were evaluated by the vendor, Framatome Technology, Inc. (FTI), with regard to impact to the OTSG and reactor vessel. Effects of the transient were determined to be bounded by limits of existing analyses.

The isolation of "B" OTSG, which provides the only source, other than the startup boiler, of gland seal steam for the main turbine, resulted in degradation of vacuum in the main condenser. RCS temperature control was shifted through the Atmospheric Dump Valve (ADV) on "A" OTSG beginning at approximately 0348. Steam pressure was controlled by the modulating motor-operated ADV isolation valve per existing procedural guidance until the startup boiler was available to supply gland seal steam. Gland seal steam was restored at 0445, and condenser vacuum was restored at 0549.

A gagging device was installed on the open MSSV at 0853. Restoration of water level in "B" OTSG using EFW began at 0916. The MSLI was cleared, normal feed water established to both OTSGs, and the plant restored to normal hot shut down conditions. The NUE was terminated at 1304 on May 19, 1996. ANO-1 remained in hot shutdown conditions while the transient was evaluated and repairs and testing were completed. The reactor was critical at 0440 on May 24, 1996, and full power was reached at 1933 on May 25, 1996.

C. Root Cause

The cause of the initiating event was a component failure in the "A" MFWP control system. Reduced voltage on the turbine control system 24 volt power supply bus resulted from a short circuit in one of the

pump speed sensing probes. The speed probe provides speed indication and an interlock for the turning gear but is not used for speed control. It is a potted assembly, and it has not been disassembled to evaluate the specific failure mechanism. According to the probe vendor, this was the first known instance of this probe failing with a short circuit. Previous failures involved an open circuit condition. An open circuit would not have caused an adverse impact upon the MFWP control system. An upgrade to the feed pump control system was installed in 1995 for the purpose of improving system response to a MFWP trip. The equipment design specifications required failure immunity and redundancy to ensure a highly fault tolerant system. Although separate fusing of non-critical components was not explicitly stated in the design specification, failure to provide such protection was inconsistent with good design practice. This is considered to be the root cause.

The probable cause for the second MFWP inappropriately transferring to manual was inappropriate equipment specification. Signal failure detection logic in the MFWP controls requires that the input exceed either a maximum or minimum value while changing in excess of a rate of change setpoint. Recorded data indicate that input rates of change were less than half of the required rate. Troubleshooting revealed that the final output device in the ICS, a signal limiter, was causing "ringing" (noise) on the MFWP speed demand input which likely caused the measured rate of change to exceed the required value. The signal limiter, which was added several years ago, is inappropriate for this application. An evaluation of the post-modification testing following the 1995 upgrade concluded that a sound approach was applied and the testing provided reasonable assurance that the logic of the control system was functional. While more elaborate testing may have identified the problem with the signal limiter, proper response to an actual ICS input was verified for the full range of the input signal. Testing also confirmed proper turbine response (entry into "Diagnostic-Manual") on rapid off-scale high and low movements of the test signal both with and without a reactor trip.

On the ANO-1 MSSVs, the spindle is a threaded extension of the valve stem that is located above the valve body. At the upper part of the spindle, a release nut is threaded on to the spindle. The release nut is prevented from rotating on the spindle by a lock (cotter) pin that is installed through a slot in the release nut and a hole in the spindle. The release nut slot is open at the upper end. The release nut serves as a leverage point for the top lever which is a part of the manual lift mechanism. During MSSV setpoint testing, the release nut is removed to allow installation of the test device. Because of incomplete engagement between the pin and the nut during the most recent installation activity, the nut vibrated and rotated down the spindle while the MSSV was open following the reactor trip. Contact between the release nut and the top lever prevented the valve from re-seating. The release nut was unable to turn because the entire valve spring load was wedging the top lever against the bottom of the release nut, preventing the valve from seating. The lift lever pin was removed and the top lever forced from under the release nut in order to provide a clearance between the top lever and release nut. Movement of the top lever allowed the release nut to turn. The cotter pin and release nut were then removed from the spindle. After removing the release nut, PSV-2685 was closed and gagged. The root cause for incomplete

engagement was determined to be "personnel work practices; document use practices; documents not followed correctly." The procedure for release nut installation was not followed correctly by ANO-1 Mechanical Maintenance personnel following the last surveillance testing of the MSSVs. A contributing factor to the MSSV failing to re-seat was determined to be an inadequate original design of the release nut. The release nut slot is approximately 0.40 inches high. This results in a very small area for the cotter pin and nut engagement to occur.

D. Corrective Actions

The speed sensing probe and the speed monitor module that was damaged by the probe failure were replaced. A fuse was also added to the digital speed monitor circuit for fault protection of the control power supplies of both MFWPs as a reliability enhancement. Changes were also made to the control setpoints to prevent undesirable transfers to the "Diagnostic-Manual" mode that isolated input signals from the ICS.

The 15 ANO-1 MSSVs (excluding PSV-2685 that remained gagged) were inspected. Cotter pins for two other valves were found not engaged in the release nuts. These valves were determined to have been operable since the release nuts could not be rotated due to the cotter pin ends being engaged on the nuts. Six valves had the pins partially engaged at the top end of the release nut slot. Seven valves were found with the cotter pins fully engaged. A modification was installed to replace the 15 MSSV release nuts with a "taller" nut with a slot dimension increased to 0.75 inches to significantly minimize the possibility of future instances of inadequate cotter pin engagement.

The ANO-1 maintenance procedure for release nut installation requires, "replace the release nut, flat side down, and temporarily install the cap and lever in order to adjust the release nut position. The bottom of the release nut should clear the top of the lever by 1/16 to 1/8 inches. Remove the lever and cap. Insert a new stainless steel cotter pin through the release nut slots and spindle and spread the cotter pin ends." These requirements came directly from the vendor technical manual. During discussions with the MSSV vendor, Dresser, it was discovered that the 1/8 inch dimension was not a functional or practical requirement because holes in the spindles are not drilled in the same locations on all spindles provided by Dresser. The maintenance procedure was changed to indicate that the 1/16 inch was a minimum clearance. Reference to the maximum clearance was deleted. A caution regarding adequate cotter pin engagement was also added to the procedure.

An inspection of the installed ANO-1 pressurizer code safety valves, ANO-2 MSSVs, and spare ANO-2 pressurizer code safety valves identified no concerns similar to those associated with the failure of PSV-2685.

The ANO-1 Plant Manager has reviewed this event with Unit 1 Mechanical Maintenance personnel to emphasize the importance of procedural adherence. Similar discussions will be conducted with appropriate personnel from the Operations and Maintenance organizations of both units and Modifications personnel. These discussions will be completed by September 15, 1996. Additional initiatives previously implemented to address procedure usage issues are being utilized to validate the ability to use procedures as written in complete compliance with site directives and administrative procedural requirements. This includes observations of procedure usage by staff or craft personnel of all Maintenance disciplines to verify and validate proper use.

E. Safety Significance

Performance of Operations personnel in bringing the plant to a safe and stable condition was competent, professional, and produced satisfactory results. One OTSG and both trains of EFW remained available throughout the event. No other safety-related equipment potentially used for reactor core cooling or any other system potentially used to mitigate the effects of the MFWP unavailability was affected by the sequence of events. The open MSSV had the effect of removing heat from the RCS until "B" OTSG reached dry-out conditions. Each of these considerations provided mitigation to the safety significance of the event.

Considering the conditions that occurred during and following the trip, an evaluation determined that the Conditional Core Damage Probability (CCDP) was similar to that expected for industry loss of MFW events. The CCDP was estimated to be above the screening criterion for low risk events but within the lowest range of events analyzed in NUREG/CR-4674, "Precursors to Potential Severe Core Damage Accidents," i.e., between 1E-06 and 1E-05. The impact of the atypical elements of this transient are mitigated by:

- the Auxiliary Feed Water Pump was available and utilized (although its inventory source, the condenser hotwell, was temporarily in a limited capacity due to a partial loss of condenser vacuum);
- the EOPs provided for the ability for EFW "trickle feed" to the OTSG that was rendered temporarily unisolable by the open MSSV; and
- the RCS pressure reduction due to the slight over-cooling transient was limited to several hundred pounds above the safety systems actuation setpoint, essentially eliminating any potential for safeguards actuation induced primary safety valve lifting.

Although these mitigating factors possibly could be utilized analytically to reduce the CCDP below the screening criterion for low risk events, as a minimum they provide confirmation that this event was within the lowest range of events that are analyzed in the Accident Sequence Precursor Program. Therefore, this event is evaluated to have a low level of safety significance.

F. Basis for Reportability

The automatic reactor trip, automatic EFW actuation, manual HPI actuation, and manual MSLI actuation constitute events reportable in accordance with 10CFR50.73(a)(2)(iv) as Reactor Protection System or Engineered Safety Features actuations. This event was reported to the NRC Operations Center at 0402 on May 19, 1996, in accordance with 10 CFR50.72(a)(1)(i) for declaration of the NUE; 10CFR50.72(b)(1)(iv) for HPI injection into the RCS; and 10CFR50.72(b)(2)(ii) for the reactor trip and actuation of EFW, HPI, and MSLI. Updates were provided at 0600, 1324, and 2154. Termination of the NUE was reported during the 1324 update.

G. Additional Information

There was one previous similar event reported by ANO as a Licensee Event Report (LER). A Main Steam Safety Valve failing to re-seat because the cotter pin did not prevent the release nut from binding with the top lever was reported as part of LER 50-313/89-018-00 (letter 1CAN058915). The 1989 event was due to a missing pin, not one with inadequate engagement. The corrective action for that event was a change to the maintenance procedure to require initials verifying pin replacement.

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].