50-280

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

August 11, 1999

Mr. J. P. O'Hanlon
Senior Vice President - Nuclear
Virginia Electric and Power Company
5000 Dominion Blvd.
Glen Allen, Virginia 23060

SUBJECT: REVIEW OF PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF OPERATIONAL EVENT AT SURRY POWER STATION, UNIT 1

Dear Mr. O'Hanlon:

Enclosed for your review and comment is a copy of the preliminary Accident Sequence Precursor (ASP) analysis of an operational condition which was discovered at Surry Power Station, Unit 1, on May 9, 1998 (Enclosure 1), and was reported in Licensee Event Report (LER) No. 280/98-009. This analysis was prepared by our contractor at the Oak Ridge National Laboratory (ORNL). The results of this preliminary analysis indicate that this condition may be a precursor for 1998. 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 condition is made publicly available. As soon as our final analysis of the condition has been completed, we will provide for your information the final precursor analysis of the condition and the resolution of your comments.

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. 280/98-009, which documented the condition.

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Please contact me at 301-415-1448 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,

ORIGINAL SIGNED BY:

Gordon E. Edison, Senior Project Manager, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No.: 50-280

Enclosures: As stated

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Enclosures: As stated

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LER No. 280/98-009

Event Description: Unisolable reactor coolant system leak

Date of Event: May 9, 1998

Plant: Surry Power Station, Unit 1

Event Summary

Surry Power Station, Unit 1 (Surry 1), was shut down after personnel discovered an unisolable 0.25-gal/min leak in the reactor coolant system (RCS) seal injection line to the C reactor coolant pump (RCP). The leak was at the RCP thermal barrier and was caused by thermal fatigue coupled with vibration stress acting on a preexisting fault in the toe of a pipe weld. The vibration stress was the result of a loose rod hanger. The estimated conditional core damage probability (CCDP) associated with this event is 1.4×10^{-5}.

Event Description

On May 9, 1998, with Surry 1 at 100% power, operators noted an increase in the RCS leak rate. The leakage was within Technical Specification (TS) limits [0.25 gal/min (Ref. 1) vs. 1.0 gal/min (TS)]. Operations personnel entered containment and reported a leak near the 1.5-in. seal injection line to the C RCP at the thermal barrier. Operators reduced the power level to 50% to reduce radiation levels in the containment building so that personnel could determine the exact location of the leak. A weld leak on the seal injection line near the C RCP thermal barrier was confirmed. Surry 1 proceeded to cold shutdown and an Unusual Event was declared.[2]

The C RCP seal injection line was removed from the RCP thermal barrier. The failed weld was excavated and a new line was welded in place. A root cause evaluation determined that a preexisting flaw existed in the toe of the failed weld. The most probable causes for the weld failure were a lack of fusion of the weld material or thermal fatigue coupled with vibration stress. A loose rod hanger that supports the seal injection line may have contributed to the vibration stress.[2]

Additional Event-Related Information

Each RCS loop contains a vertical single stage centrifugal pump with a controlled leakage seal assembly. The controlled leakage seal assembly (primary seal) restricts leakage along the pump shaft. A second seal directs leakage past the primary seal and out of the pump. A third seal minimizes the leakage of water and vapor from the pump into the containment atmosphere. Some high-pressure water from the charging pumps is injected into the RCP between the impeller and the controlled leakage seal. [The charging pumps also serve as the high-pressure injection (HPI) pumps when required.] Part of the charging water flow enters the RCS through a labyrinth seal in the lower pump shaft to serve as a buffer to keep hot reactor coolant from entering the upper portion of the pump. The remainder of the seal injection flow is directed along the drive shaft through the primary seal and back to the charging system through the seal-water heat exchanger. Component cooling water is supplied to cooling coils around the labyrinth seal (thermal barrier) in the lower pump shaft. This thermal barrier heat exchanger serves to remove heat from any RCS coolant that may leak up the RCP shaft if the seal injection flow is interrupted.[3]

The reported leak was in a weld on the 1.5-in. seal injection line just above the thermal barrier. A catastrophic failure of the seal injection line at this weld would allow high pressure RCS coolant to leak past the thermal barrier and out the failed seal injection line. This RCS loss of coolant could not be isolated. Hence, a break in the seal injection line would be an unisolable small-break LOCA.

Emergency Diesel Generator (EDG) #2 was unavailable during this event because of maintenance. This EDG is dedicated to Unit 2 and would not affect this event unless further complications from a loss of offsite power (LOOP) were to occur during a LOCA.

Modeling Assumptions

This event was modeled as a potential small-break LOCA in the seal injection line to the C RCP. In the actual event, the pipe crack developed slowly and began to leak. This leakage was detected, and the plant was shut down while the seal injection line remained substantially intact. It is possible, however, that the crack could have developed differently, resulting in catastrophic failure of the injection line before detection. NUREG/CR-6582, *Assessment of Pressurized Water Reactor Primary System Leaks*[4], shows those leak types with the highest potential for relatively rapid growth include leaks through thermal fatigue cracks in branch lines, such as existed in this case.

The probability of a "rupture-before-leak" failure mode was estimated using service-based piping reliability data developed by the Swedish Nuclear Power Inspectorate (SKI).[5] The probability of pipe rupture represents the likelihood that a defect could have progressed to a rupture. The conditional probability of a seal injection line rupture was estimated using data related to thermal-fatigue-induced piping failures included in the recently developed SKI piping failure database.[5] The SKI database currently includes more than 2300 pipe failure records that represent about 4300 reactor-years of operating experience. For failures due to thermal fatigue, 18 cracks and leaks, but no ruptures, were observed in stainless steel piping 1 to 2 in. in diameter. Using Bayesian statistics with a noninformative prior[a], a conditional probability of rupture because of thermally induced fatigue of 2.4×10^{-2} was estimated.[b] Because no ruptures have occurred because of this mechanism,

[a]The use of a noninformative prior is described on page 5-36 of the *PRA Procedures Guide*, NUREG/CR-2300, January 1983. A number of alternate estimators have been proposed for the case where no failures have been observed. See, for example, Section 5.5 of NUREG/CR-2300 and R. T. Bailey's article "Estimation from Zero-Failure Data" in *Risk Analysis*, Vol. 17, No. 3, June 1997.

[b]An alternative to the "data-driven" model that constitutes the SKI effort is the application of probabilistic fracture mechanics models. These models enable the calculation of failure probabilities assuming that piping is susceptible to anticipated degradation mechanisms especially those that develop over a long period. Ref. 5 notes that under a similar set of boundary conditions, the two approaches tend to produce similar (i.e., the same order of magnitude) results.

this estimate is uncertain. If a much larger experience base were available, it is possible that the estimated probability for a rupture-before-leak failure occurring would be lower. However, several thermal fatigue-induced failures also included cyclic fatigue (vibration-induced fatigue) as a contributing factor (as noted in the **Event Description**, this may have been the case in this event as well). Among the 78 failures reported in the SKI data base, two cyclic fatigue-related ruptures have been observed. Again, using a Bayesian statistic with a noninformative prior, an estimated conditional probability of cyclic fatigue-related ruptures of 3.2×10^{-2} was estimated. This is approximately the same conditional probability as the 2.4×10^{-2} estimate for thermally induced fatigue-related ruptures. These values are consistent with the average number of piping failures that are ruptures estimated in 1981 by Thomas (Ref. 6)[a] and are about a factor of 4 smaller than the break-before-leak probability developed by the Electric Power Research Institute (EPRI) in 1992 (Ref. 7).[b]

Because a 1.5-in. break would be a small-break LOCA, the initiating frequency was adjusted from 2.3×10^{-6} to 2.4×10^{-2} for this leak event to account for the increased likelihood of a fatigue-related rupture. Because the leak location was not isolable, the basic event representing the probability of failure to isolate a small-break LOCA in the short-term (SLOCA-XHE-NOREC) was adjusted from 4.3×10^{-1} to 1.0 (TRUE).

The Accident Sequence Precursor (ASP) model for Surry was also revised to address the probability of rapidly depressurizing the RCS and using the low-pressure injection (LPI) system to cool the core if HPI were to fail. The Surry individual plant examination (IPE) report[7] states that the operators are directed to use secondary heat removal capabilities to depressurize the RCS until LPI flow is sufficient to cool the core. The probability of the operators failing to depressurize the RCS and initiating LPI was assumed to be 0.31, consistent with Ref. 8.

A seal line rupture would also reduce injection flow to the other two RCPs. This would allow warmer RCS coolant to leak through the primary seal of the unaffected RCPs; warmer RCS coolant could affect the life of these RCP seals. This effect was not modeled as part of this analysis. Furthermore, a seal line rupture would offer less resistance to coolant flow than nominal RCS backpressure and would allow more injection flow to exist in the seal injection line. Because charging flow and HPI flow are provided by the same pumps, a seal line rupture would reduce the amount of available HPI flow to the core. Because any reduction in HPI flow was not expected to be significant compared to nominal HPI flow, this effect was also not modeled as part of this analysis.

Analysis Results

The CCDP for a postulated small-break LOCA associated with the leaking seal injection line weld is estimated to be 1.4×10^{-5}. The dominant sequence, sequence 13 in Fig. 1, involves

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[a]Reference 6 estimated that between 2 and 45% (on average, ~6%) of piping failures were catastrophic, depending on the failure cause. Unfortunately, piping failures caused by high-cycle fatigue were not separately enumerated. Reference 6 further estimates that with respect to catastrophic failures, 3% were low-cycle fatigue failures, 20% were vibration-related fatigue failures, and 20% were associated with "thermal shock."

[b]Reference 7 estimated that the probability of a break-before-leak varied from 0.09 to 0.11, depending on pipe size.

- a postulated seal injection line break (small-break LOCA) given the weld leak,
- successful reactor trip and secondary side cooling,
- failure to isolate the small-break LOCA in the short term,
- failure of HPI, and
- failure to rapidly cool down and depressurize to LPI pressures.

The dominant sequence accounts for one-half (50%) of the total contribution to the CCDP. The dominant cut sets in this sequence involve an operator failure to cool down and depressurize the RCS in a timely manner following a failure of HPI.

The next most dominant sequence, sequence 4 in Fig. 1, involves

- a postulated seal injection line break (small-break LOCA) given the weld leak,
- successful reactor trip and secondary side cooling,
- failure to isolate the small-break LOCA in the short term,
- successful HPI and primary cooldown to RHR entry conditions,
- failure of RHR,
- successful containment spray recirculation (CSR), and
- failure of high-pressure recirculation (HPR).

This sequence accounts for an additional 42% of the total contribution to the CCDP. The dominant cut sets in this sequence involve failures of 4160-V ac buses 1H and 1J. These individual bus failures affect, among others, the following components:

- RHR suction valves MOV 1700 (powered from bus 1H) and MOV 1701 (powered from bus 1J); because these valves are in series and both valves have to open in order to have successful RHR, the loss of either bus will result in a loss of RHR,
- RWST supply valves MOV 1115B (powered from bus 1H) and MOV 1115D (powered from bus 1J); because these valves are in parallel and both valves have to close in order to have successful HPR, failure to close either valve will result in a loss of HPR.

Hence, the failure of bus 1H or bus 1J will result in the failure of RHR and HPR.

Substantial uncertainty is associated with the CCDP estimated for this event, primarily because of uncertainty in the conditional probability of pipe rupture. In addition to the uncertainty related to zero-event data described in **Modeling Assumptions**, Ref. 5 describes, among others, the following sources of uncertainty: coverage and completeness of the SKI data collection effort, data aggregation and exposure time estimation issues, identification of appropriate reliability attributes (e.g., pipe diameter, piping material) and influence factors (such as design and operating practices), plant-to-plant differences, and in-plant differences. In one probabilistic fracture mechanics study[a] cited in Ref. 5, a three orders of magnitude difference existed in the

[a]*Probabilistic Pipe Fracture Evaluations for Leak-Rate Detection Applications*, NUREG/CR-6004, 1995.

conditional rupture probability for leaking 100–800 mm pipe ($10^{-4} \le p \le 10^{-1}$), depending on (1) the material, (2) whether the crack was in the base metal, or (3) if the crack was in a weld (as it was for this event). For stainless steel, the conditional probability for weld cracks was about two orders of magnitude higher than for cracks in base metal.

Definitions and probabilities for selected basic events are shown in Table 1. The conditional probabilities associated with the highest probability sequences are shown in Table 2. Table 3 lists the sequence logic associated with the sequences listed in Table 2. Table 4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table 5.

Acronyms

ASP	accident sequence precursor
CCDP	conditional core damage probability
CSR	containment spray recirculation
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
HPI	high-pressure injection
HPR	high-pressure recirculation
IPE	individual plant examination
IRRAS	Integrated Reliability and Risk Analysis System
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPI	low-pressure injection
LPR	low-pressure recirculation
MDP	motor-driven pump
MOV	motor-operated valve
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RWST	refueling water storage tank
SKI	Swedish Nuclear Power Inspectorate
TS	technical specifications

References

1. 10 CFR 50, Part 50.72 report # 34200.

2. LER 280/98-009, Rev. 0, "Nonisolable Leak of Reactor Coolant Pump Seal Injection Line Weld," June 3, 1998.

3. Surry Power Station Units 1 & 2, *Updated Final Safety Analysis Report.*

4. Shah, V. N., et. al., *Assessment of Pressurized Water Reactor Primary System Leaks*, NUREG/CR-6582, December 1998.

5. R. Nyman, D. Hegedus, B. Tomic, and B. Lydell, *Reliability of Piping System Components, Framework for Estimating Failure Parameters from Service Data*, SKI Report 97:26, December 1997.

6. H. M. Thomas, "Pipe and Vessel Failure Probability," *Reliability Engineering*, 2:83 (1981).

7. *Pipe Failures in U.S. Commercial Nuclear Power Plants*, EPRI TR-100380, July 1992.

8. Virginia Electric and Power Company, *Probabilistic Risk Assessment for the Individual Plant Examination, Final Report, Surry Units 1 and 2*, August 1991.

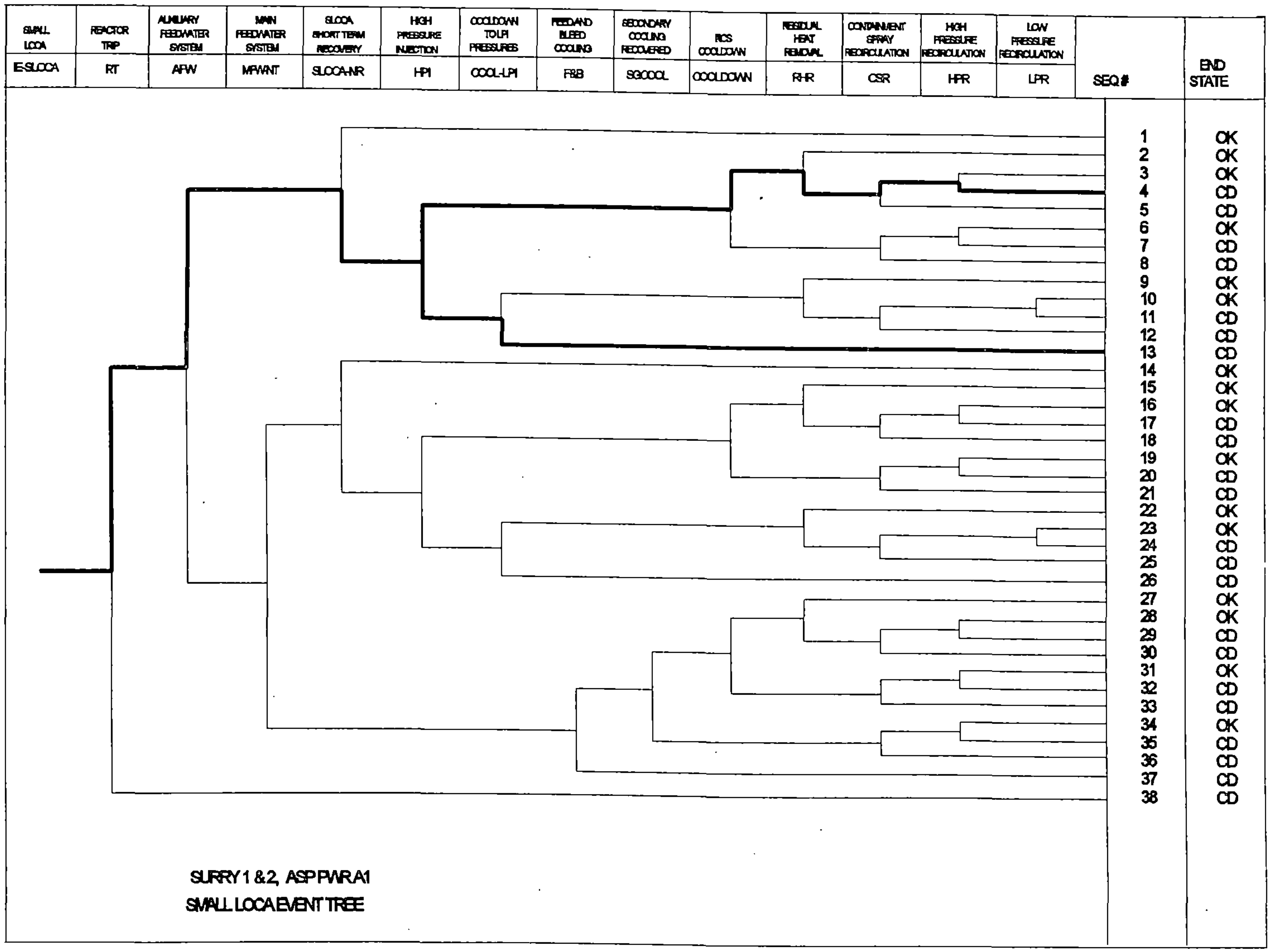

Fig. 1. Dominant core damage sequence for LER No. 280/98-009.

Table 1. Definitions and Probabilities for Selected Basic Events for LER No. 280/98-009

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–LOOP (Excludes the Probability of Recovering Offsite Power in the Short Term)	1.6 E-005	0.0 E+000		Yes
IE-SGTR	Initiating Event–Steam Generator Tube Rupture	1.6 E-006	0.0 E+000		Yes
IE-SLOCA	Initiating Event–Small-Break LOCA	2.3 E-006	2.4 E-002		Yes
IE-TRANS	Initiating Event–Transient	3.2 E-004	0.0 E+000		Yes
ACP-BAC-LP-1H	Division 1H ac Power 4160V Bus Fails	9.0 E-005	9.0 E-005		No
ACP-BAC-LP-1J	Division 1J ac Power 4160V Bus Fails	9.0 E-005	9.0 E-005		No
EPS-DGN-FC-2	EDG 2 Fails	3.0 E-002	1.0 E+000	TRUE	Yes
FRC1-XHE-XM	Operator Fails to Cool Down and Depressurize the RCS in a Timely Manner Following HPI Failure	3.1 E-001	3.1 E-001	NEW	No
HPI-CKV-CC-DIS	Failure of HPI Discharge Check Valves	1.0 E-004	1.0 E-004		No
HPI-CKV-CC-SUCT	Failure of HPI Suction Check Valves From RWST	2.0 E-004	2.0 E-004		No
HPI-MDP-CF-RUN	Common-Cause Failure of HPI Pumps to Run	2.2 E-005	2.2 E-005		No
HPI-MOV-CF-DIS	Common-Cause Failure of HPI Discharge Motor-Operated Valves (MOVs)	2.6 E-004	2.6 E-004		No
HPI-MOV-CF-SUCT	Common-Cause Failure of HPI Suction MOVs From the Refueling Water Storage Tank (RWST)	2.6 E-004	2.6 E-004		No
HPI-MOV-CF-VCT	Common-Cause Failure of HPI Suction MOVs From the Volume Control Tank	2.6 E-004	2.6 E-004		No
HPI-MOV-OO-RWSTA	HPI /RWST Isolation MOV 1115B Fails	3.0 E-003	3.0 E-003		No

Table 1. Definitions and Probabilities for Selected Basic Events for LER No. 280/98-009 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-MOV-OO-RWSTB	HPI /RWST Isolation MOV 1115D Fails	3.0 E-003	3.0 E-003		No
HPR-XHE-XM	Operator Fails to initiate the HPR System	1.0 E-003	1.0 E-003		No
LPI-MDP-CF-AB	Common-Cause Failure of LPI Motor-Driven Pumps	5.6 E-004	5.6 E-004		No
LPR-MOV-CF-HPR	Common-Cause Failure of Cross-Tie MOVs to HPR	2.6 E-004	2.6 E-004		No
LPR-MOV-CF-RWST	Common-Cause Failure of LPR RWST Isolation Valves	2.6 E-004	2.6 E-004		No
LPR-MOV-CF-SUMP	Common-Cause Failure of Sump Isolation Valves	2.6 E-004	2.6 E-004		No
PCS-VCF-HW	Turbine Bypass Valves/ Condenser/ Circulating Water Failures	3.0 E-003	3.0 E-003		No
PCS-XHE-XM-CDOWN	Operator Fails to Initiate Cool Down	1.0 E-003	1.0 E-003		No
RHR-MOV-CC-SUCA	RHR Suction MOV 1700 Fails	3.0 E-003	3.0 E-003		No
RHR-MOV-CC-SUCA	RHR Suction MOV 1701 Fails	3.0 E-003	3.0 E-003		No
RHR-XHE-XM	Operator Fails to Activate the RHR System	1.0 E-003	1.0 E-003		No
SLOCA-04-NREC	SLOCA Sequence 04 Non-Recovery Probability – Failure to Recover HPR	1.0 E+000	1.0 E+000		No
SLOCA-07-NREC	SLOCA Sequence 07 Non-Recovery Probability – Failure to Recover HPR	1.0 E+000	1.0 E+000		No
SLOCA-10-NREC	SLOCA Sequence 10 Non-Recovery Probability – Failure to Recover HPI	8.4 E-001	8.4 E-001		No
SLOCA-XHE-NOREC	Operator Fails to Recover From an SLOCA in the Short-Term	4.3 E-001	1.0 E+000	TRUE	Yes

Table 2. Sequence Conditional Probabilities for LER No. 280/98-009

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
SLOCA	13	7.2 E-006	49.9
SLOCA	04	6.0 E-006	41.7
SLOCA	07	8.4 E-007	5.8
Total (all sequences)		**1.4 E-005**	

Table 3. Sequence Logic for Dominant Sequences for LER No. 280/98-009

Event tree name	Sequence number	Logic
SLOCA	13	/RT, /AFW, SLOCA-NR, HPI, COOL-LPI
SLOCA	04	/RT, /AFW, SLOCA-NR, /HPI, /COOLDOWN, RHR, /CSR, HPR
SLOCA	07	/RT, /AFW, SLOCA-NR, /HPI, COOLDOWN, /CSR, HPR

Table 4. System Names for LER No. 280/98-009

System name	Logic
AFW	No or Insufficient Flow From the Auxiliary Feedwater System
COOL-LPI	Rapid Cool Down and Depressurization to LPI Pressures
COOLDOWN	RCS Cool Down to Residual Heat Removal (RHR) System Pressure Using Turbine Bypass Valves, Condenser, and Circulating Water
CSR	No or Insufficient Containment Spray Recirculation Flow
HPI	No or Insufficient Flow From the HPI System
HPR	No or Insufficient HPR Flow
RHR	No or Insufficient Flow From the RHR System
RT	Reactor Fails to Trip During a Transient
SLOCA-NR	Small-Break LOCA Recovery in Short-Term

Table 5. Conditional Cut Sets for Higher Probability Sequences for LER No. 280/98-009

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
SLOCA Sequence 13		7.2 E-006	
1	22.9	1.6 E-006	SLOCA-XHE-NOREC, HPI-MOV-CF-VCT, FRC1-XHE-XM, SLOCA-10-NREC
2	22.9	1.6 E-006	SLOCA-XHE-NOREC, HPI-MOV-CF-DIS, FRC1-XHE-XM, SLOCA-10-NREC
3	22.9	1.6 E-006	SLOCA-XHE-NOREC, HPI-MOV-CF-SUCT, FRC1-XHE-XM, SLOCA-10-NREC
4	17.4	1.2 E-006	SLOCA-XHE-NOREC, HPI-MOV-CC-SUCT, FRC1-XHE-XM, SLOCA-10-NREC
5	8.7	6.2 E-007	SLOCA-XHE-NOREC, HPI-MOV-CC-DIS, FRC1-XHE-XM, SLOCA-10-NREC
6	1.9	1.4 E-007	SLOCA-XHE-NOREC, HPI-MDP-CF-RUN, FRC1-XHE-XM, SLOCA-10-NREC
SLOCA Sequence 04		6.0 E-006	
1	35.9	2.2 E-006	SLOCA-XHE-NOREC, ACP-BAC-LP-1H, SLOCA-04-NREC
2	35.9	2.2 E-006	SLOCA-XHE-NOREC, ACP-BAC-LP-1J, SLOCA-04-NREC
3	3.6	2.2 E-007	SLOCA-XHE-NOREC, RHR-MOV-CC-SUCA, HPI-MOV-OO-RWSTA, SLOCA-04-NREC
4	3.6	2.2 E-007	SLOCA-XHE-NOREC, RHR-MOV-CC-SUCB, HPI-MOV-OO-RWSTA, SLOCA-04-NREC
5	3.6	2.2 E-007	SLOCA-XHE-NOREC, RHR-MOV-CC-SUCA, HPI-MOV-OO-RWSTB, SLOCA-04-NREC
6	3.6	2.2 E-007	SLOCA-XHE-NOREC, RHR-MOV-CC-SUCB, HPI-MOV-OO-RWSTB, SLOCA-04-NREC
7	1.2	7.2 E-008	SLOCA-XHE-NOREC, RHR-XHE-XM, HPI-MOV-OO-RWSTA, SLOCA-04-NREC
8	1.2	7.2 E-008	SLOCA-XHE-NOREC, RHR-XHE-XM, HPI-MOV-OO-RWSTB, SLOCA-04-NREC
9	1.2	7.2 E-008	SLOCA-XHE-NOREC, RHR-MOV-CC-SUCA, HPR-XHE-XM, SLOCA-04-NREC

Table 5. Conditional Cut Sets for Higher Probability Sequences for LER No. 280/98-009 (continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
10	1.2	7.2 E-008	SLOCA-XHE-NOREC, RHR-MOV-CC-SUCB, HPR-XHE-XM, SLOCA-04-NREC
SLOCA Sequence 07		8.4 E-007	
1	25.8	2.2 E-007	SLOCA-XHE-NOREC, PCS-VCF-HW, HPI-MOV-OO-RWSTA, SLOCA-07-NREC
2	25.8	2.2 E-007	SLOCA-XHE-NOREC, PCS-VCF-HW, HPI-MOV-OO-RWSTB, SLOCA-07-NREC
3	8.6	7.2 E-008	SLOCA-XHE-NOREC, PCS-VCF-HW, HPR-XHE-XM, SLOCA-07-NREC
4	8.6	7.2 E-008	SLOCA-XHE-NOREC, PCS-XHE-XM-CDOWN, HPI-MOV-OO-RWSTA, SLOCA-07-NREC
5	8.6	7.2 E-008	SLOCA-XHE-NOREC, PCS-XHE-XM-CDOWN, HPI-MOV-OO-RWSTB, SLOCA-07-NREC
6	4.8	4.0 E-008	SLOCA-XHE-NOREC, PCS-VCF-HW, LPI-MDP-CF-AB, SLOCA-07-NREC
7	2.9	2.4 E-008	SLOCA-XHE-NOREC, PCS-XHE-XM-CDOWN, HPR-XHE-XM, SLOCA-07-NREC
8	2.3	1.9 E-008	SLOCA-XHE-NOREC, PCS-VCF-HW, LPR-MOV-CF-HPR, SLOCA-07-NREC
9	2.3	1.9 E-008	SLOCA-XHE-NOREC, PCS-VCF-HW, LPR-MOV-CF-SUMP, SLOCA-07-NREC
10	2.3	1.9 E-008	SLOCA-XHE-NOREC, PCS-VCF-HW, LPR-MOV-CF-RWST, SLOCA-07-NREC
11	1.6	1.3 E-008	SLOCA-XHE-NOREC, PCS-XHE-XM-CDOWN, LPI-MDP-CF-AB, SLOCA-07-NREC
Total (all sequences)		**1.4 E-005**	

[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 cut set. The probability of the initiating events are given in Table 1 and begin with the designator "IE." The probabilities for the basic events also are given in Table 1.

[b]Basic event, SLOCA-XHE-NOREC, is a TRUE type event which is not normally included in the output of fault tree reduction programs but has been added to aid in understanding the sequences to potential core damage associated with the event.

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 1998 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 G 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 mitigated by the use of the standby feedwater system. The

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* Revision or practices at the time the event occurred.

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. R. J. Belles et al., "Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report," USNRC Report NUREG/CR-4674 (ORNL/NOAC-232) Volume 26, Lockheed Martin Energy Research Corp., Oak Ridge National Laboratory, and Science Applications International Corp., Oak Ridge, Tennessee, November 1998.

10CFR50.73

Virginia Electric And Power Company
Surry Power Station
5570 Hog Island Road
Surry, Virginia 23883

June 3, 1998

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D. C. 20555

Serial No.: 98-330
SPS: JCS
Docket No.: 50-280
License No.: DPR-32

Dear Sirs:

Pursuant to 10CFR50.73, Virginia Electric and Power Company hereby submits the following Licensee Event Report applicable to Surry Power Station Unit 1.

Report No. 50-280/1998-009-00

This report has been reviewed by the Station Nuclear Safety and Operating Committee and will be forwarded to the Management Safety Review Committee for its review.

Very truly yours,

D. A. Christian
Site Vice President

Enclosure

Commitments contained in this letter:

1. The Unit 2 piping and supports will be inspected during the next refueling outage to verify proper installation and adjustment.
2. Approved RCE recommendations that are needed to prevent a recurrence of this event will be implemented.

Je22

2pp.

Enclosure 3

cc: U. S. Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
Atlanta, Georgia 30303

Mr. R. A. Musser
NRC Senior Resident Inspector
Surry Power Station

NRC FORM 366 (4-95) | U.S. NUCLEAR REGULATORY COMMISSION | APPROVED BY OMB NO. 3150-0104 EXPIRES 4/30/98

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
SURRY POWER STATION , Unit 1	05000 - 280	1 OF 3

TITLE (4)
Nonisolable Leak of Reactor Coolant Pump Seal Injection Line Weld

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	DOCUMENT NUMBER 05000-
05	09	98	1998	-- 009 --	00	06	03	98	FACILITY NAME	DOCUMENT NUMBER 05000-

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

OPERATING MODE (9)	NA		20.2201(b)		20.2203(a)(2)(v)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)
POWER LEVEL (10)	100 %		20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)		50.73(a)(2)(iv)		OTHER
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		or in NRC Form 366A

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
D. A. Christian, Site Vice President	(757) 365-2000

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

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE	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)

On May 9, 1998, with Unit 1 at 100% power, an increase was noted in Reactor Coolant System (RCS) leakage. Operations personnel entered the containment to investigate and discovered a leak in the area of the 1½" seal injection line to the "C" Reactor Coolant Pump (RCP) at the pump thermal barrier. A subsequent containment entry confirmed that a weld or pipe through-wall non-isolable leak existed at the seal injection line of the RCP. The unit was placed at cold shutdown as required by TS 3.1.C.4. On May 9, 1998, a Notice of Unusual Event was declared and, at 2316, the NRC was notified in accordance with 10CFR50.72(a)(1)(i) and 10CFR50.72(b)(1)(i)(A). The seal injection line was repaired and the unit was prepared for start-up and the unit was returned to service on May 25, 1998. A Root Cause Evaluation (RCE) was initiated to verify the cause of the leaking "C" RCP seal injection weld. The cause has preliminarily been determined to be from a pre-existing indication at the toe of the weld. The most probable cause for the weld failure was a lack of fusion or thermal fatigue coupled with vibration stress due to a loose rod hanger. This event is reportable pursuant to 10CFR50.73(a)(2)(i)(B).

3pp

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Surry Power Station, Unit 1	05000 - 280	1998	– 009 –	00	2 OF 3

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

1.0 DESCRIPTION OF THE EVENT

On May 9, 1998, with Unit 1 at 100% power, an increase was noted in Reactor Coolant System (RCS) leakage. The leakage was within Technical Specification (TS) limits and monitoring revealed that the leakage rate had increased only slightly. Operations personnel entered the containment to investigate and discovered a leak in the area of the 1½" seal injection line to the "C" Reactor Coolant Pump (RCP) [EIIS-AB-P] at the pump thermal barrier. A unit ramp down to 50% power was commenced to reduce dose in the area of the leak so that a second containment entry could be made to further examine the leak. The second containment entry confirmed that a weld or pipe through-wall non-isolable leak existed at the seal injection line of the RCP. As a result, the unit was placed at cold shutdown as required by TS 3.1.C.4. On May 9, 1998, a Notice of Unusual Event was declared and, at 2316, the NRC was notified in accordance with 10CFR50.72(a)(1)(i) and 10CFR50.72(b)(1)(i)(A). The seal injection line was repaired and the unit was returned to service on May 25, 1998. This event is reportable pursuant to 10CFR50.73(a)(2)(I)(B) as a condition prohibited by Technical Specifications.

2.0 SIGNIFICANT SAFETY CONSEQUENCES AND IMPLICATIONS

RCS leakage is quantified daily including unidentified leakage. The leakage from the seal injection line to the RCP thermal barrier was detected by the daily leakage evaluation and was confirmed by visual inspection. The leak rate was less than the unidentified leakage limits specified in TS 3.1.C.2. A catastrophic failure of the weld is unlikely, but if it were to occur, the resultant loss of RCS inventory would be bounded by existing accident analyses. Therefore, the health and safety of the public were not affected.

3.0 CAUSE

A Root Cause Evaluation was initiated to verify the cause of the leaking "C" RCP seal injection weld. The cause has preliminarily been determined to be from a pre-existing indication at the toe of the weld. The most probable cause for the weld failure was a lack of fusion or thermal fatigue coupled with vibration stress due to a loose rod hanger [EIIS-AB-H].

4.0 IMMEDIATE CORRECTIVE ACTION(S)

The RCP seal injection line was removed from the RCP thermal barrier. The failed weld was excavated and a new line was welded in place in accordance with approved procedures.

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Surry Power Station, Unit 1	05000 - 280	1998	– 009 –	00	3 OF 3

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

5.0 ADDITIONAL CORRECTIVE ACTIONS

The rod hanger for "C" RCP seal injection line was adjusted.

6.0 ACTIONS TO PREVENT RECURRENCE

The corresponding welds for "A" and "B" RCP seal injection lines were nondestructively tested with no indications noted. The associated pipe supports were inspected to ensure proper installation. No deficiencies were identified.

The piping and support configurations for the Unit 2 RCP seal injection lines were evaluated by Engineering. Due to hanger differences between the two units, the evaluation concluded that a similar event on Unit 2 is not likely. However, the Unit 2 piping and supports will be inspected during the next refueling outage to verify proper installation and adjustment.

Approved RCE recommendations that are needed to prevent a recurrence of this event will be implemented.

7.0 SIMILAR EVENTS

S-1-93-010-00, "Operation with a Non-isolable Leak on a "B" Steam Generator Channel Head Drain Line."
S-1-95-007-01, "Operation with Non-isolable Leak in Pressurize Instrumentation Nozzles."
S-1-98-006-00, "Unisolable Through Wall Leak of RCP Thermowell."

8.0 MANUFACTURER / MODEL NUMBER

NA

9.0 ADDITIONAL INFORMATION

Unit 2 was operating at 100% and was not affected by this event.