U.S. NUCLEAR REGULATORY COMMISSION
REGION III

Report Nos. 50-237/92034(DRP); 50-249/92034(DRP)

Docket Nos. 50-237; 50-249 License Nos. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
Opus West III
1400 Opus Place
Downers Grove, IL 60515

Facility Name: Dresden Nuclear Station, Units 2 and 3

Inspection At: Dresden Site, Morris, Illinois

Inspection Conducted: December 14, 1992 through January 29, 1993

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Reactor Projects Section 1B

Inspection Summary

Inspection from December 14, 1992, through January 29, 1993 (Reports No. 50-237/92034(DRP); 50-249/92034(DRP)).

Areas Inspected: A special safety inspection conducted by the resident inspectors and the Illinois Department of Nuclear Safety inspector concerning the circumstances surrounding the degraded containment cooling service water flow identified on April 2, 1992, and the licensee's subsequent corrective actions. The special inspection included followup on previously identified items; licensee event reports; modifications and changes to the facility; review of operational safety; and events followup. Inspection modules used during this inspection were: 37828, 71707, 92700, 92701, and 93702.

Results:

Several apparent violations were identified.

- An apparent violation of 10 CFR 50.59, with multiple examples. The regulation requires Commission approval prior to making changes to the facility that involve an unreviewed safety question (paragraph 7 and 10).

- An apparent violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Actions, with two examples (paragraph 4 and 8).

- An apparent violation of 10 CFR 50, Appendix B, Criteria III, Design Control, with two examples (paragraph 6 and 9).

- An apparent violation of 10 CFR 50, Appendix B, Criteria XI, Test Control, with two examples (paragraph 8 and 12).

- An apparent violation of 10 CFR 50.72/73 reporting requirements with multiple examples (paragraph 11).

Additionally several weaknesses in the licensee's management control system were identified. These weaknesses resulted in failure to:

- Ensure the operating authority makes required NRC notification.

- Ensure engineering personnel verify assumptions used in contractor prepared analyses.

- Perform adequate safety evaluations.

- Ensure adequate corrective actions taken to repair degraded equipment.

DETAILS

1. Persons Contacted

*C. Schroeder, Station Manager
*R. Flahive, Technical Superintendent
*J. Kotowski, Operations Manager
T. O'Conner, Assistant Superintendent, Maintenance
J. Achterberg, Assistant Superintendent, Work Planning
*M. Strait, Technical Staff Supervisor
*J. Shields, Regulatory Assurance Supervisor
*H. Massin, Engineering Supervisor
*B. Viehl, Engineering Supervisor
*E. Carrol, Regulatory Assurance
*A. D'Antonio, Site Quality Verification
*J. Nash, NSSS Vendor
*S. Eldridge, Site Engineering
*J. Kish, Safety Quality Verification
*P. Piet, Licensing Administration
*T. Schuster, Licensing Superintendent
*T. Gallaher, Staff Engineer
*R. Ralph, Assistant Supervisor
*J. Gates, Assistant Technical Staff Supervisor
*S. Rhee, Technical Staff
*N. Diarindakis, Technical Staff
*C. Kent, Training
*D. Saccommando, Licensing
*R. Radtke, Site VP Staff

U.S. Nuclear Regulatory Commission

*B. Clayton, Chief, DRP Branch 1
*P. Hiland, Chief, Reactor Projects Section 1B
*I. Yin, Regional Inspector

*Denotes those attending the exit interview conducted on January 29, 1993.

The inspectors also talked with and interviewed several other licensee employees during the course of the inspection.

2. Background

The containment heat removal system (CHRS) consisted of two independent trains. Each train was designed to include:

- Two low pressure coolant injection (LPCI) pumps with a train flow of 10,700 gallons per minute (gpm).

- Two containment cooling service water (CCSW) pumps with a train flow of 7,000 gpm.

- One heat exchanger (Hx) with an original duty of 105 million british thermal units per hour (MBTU/hr) at 95°F river water temperature.

The CHRS used CCSW on the secondary side of the LPCI Hx. Two CCSW pumps (A/B & C/D) were connected to each Hx through common piping. The CCSW pumps suction source was the intake forebay (the ultimate heat sink). A motor operated valve (MOV) maintained a minimum of 20 pounds per square inch-differential (psid) across the Hx tubes to ensure no radioactive fluid passed into the environment.

Plant technical specifications (TS) limiting condition for operations (LCO) permitted reactor operation for 30 days following the loss of one of the four CCSW pumps and 7 days following the loss of two of the four pumps. Reactor operation was not permitted with less than two CCSW pumps available. The TS Surveillance required each pump to produce 3,500 gpm flow at a discharge pressure of 180 pounds per square inch-gage (psig).

3. <u>Degraded CCSW Flow Condition</u>

On April 2, 1992, operations personnel observed only 5,600 gpm CCSW train flow available on Unit 3. 7,000 gpm flow was expected based on operator training, the updated final safety analysis report (UFSAR) design flow, and Dresden Operating Procedure (DOP) 1500-2, "Torus Water Cooling Mode of Low Pressure Coolant Injection System." Unit 2 CCSW flow was not tested; however, the licensee assumed the degraded condition existed on both units.

<u>Licensee's Operability Evaluation</u>

On April 4, 1992, the licensee concluded system operability based on the following:

- An evaluation of the pre-blowdown maximum bulk and local suppression pool (SP) temperatures using the assumptions in the Mark I long term containment program and degraded CCSW flow heat removal capability.

- An evaluation of the torus attached piping (TAP) hydrodynamic loads and modifications in regard to the higher peak local SP temperatures for the limiting transient.

- The assumption that the limiting design basis accident (DBA) loss of coolant accident (LOCA) containment cooling analysis was bounded by 1 LPCI/1 CCSW pump combination (3,500 gpm) CHRS accident mitigation.

The 1 LPCI/1 CCSW pump DBA mitigation assumption contradicted the safety analysis report (SAR) discussions of the DBA containment cooling analysis and the design bases for the LPCI Hx. The SAR indicated a minimum of two CCSW pumps were required (7,000 gpm). However, the licensee concluded the SAR was in error. This conclusion was based on:

- A 1967 plant process diagram (Drawing Number 729E583), supplied by the nuclear steam supply system (NSSS) vendor. The diagram provided the results of a 1 LPCI/1 CCSW pump DBA LOCA containment heat removal analysis.

- TS Basis 3.5.B, "Containment Cooling Service Water," was interpreted to mean the 1 LPCI/1 CCSW pump combination met the minimum cooling requirements.

- Emergency diesel generator (EDG) post accident loading was limited to only one CCSW pump on each bus.

- SAR references on electrical systems indicated one CCSW pump may be started and loaded on the EDG within two hours after the DBA LOCA.

- A draft letter "clarifying" the licensing bases provided by the NSSS vendor (reference GE letter J. E. Nash to S. Mintz dated April 6, 1992).

Licensee's Corrective Actions

The licensee changed the SAR description of the plant design, to reflect the degraded flow condition. A SAR statement that two CCSW pumps were required to provide cooling capacity was changed to one pump. The SAR change and 10 CFR 50.59 safety evaluation were on-site reviewed on April 7, 1992. On August 18, 1992, DOP 1500-02 was revised to require operator verification of only 5,600 gpm CCSW train flow during accident conditions.

4. Degraded Containment Cooling Hx Heat Removal Capability

The 1967 plant process diagram predicted a 180°F SP temperature and used a Hx duty of 84.5 MBTU/hr for the limiting containment heat removal case (1 LPCI/1 CCSW pump). The inspectors identified the Hx duty value was incorrect. The overall heat transfer coefficient (U) used in the 1 LPCI/1 CCSW pump case was the same used in the 2 LPCI/2 CCSW pump case (based on a log mean temperature difference method evaluation). The inspectors estimated use of the correct U value would result in a 7 - 13% degradation in heat removal capability. The degraded duty would have resulted in a greater post accident SP temperature than predicted by the process diagram. The inspectors communicated the concern to the licensee's engineering staff on April 6, 1992.

In response to the inspectors concern, the licensee performed an evaluation (based on a graphical effectiveness solution technique) which confirmed the duty specified in the 1967 process diagram was correct. However, after reviewing the evaluation the inspectors could not validate the licensee's conclusion. The inspectors subsequently requested the original NSSS vendor's Hx duty calculations for review.

On May 15, 1992, the inspectors were notified the original duty calculations were not retrievable. However, the NSSS vendor re-calculated the 1 LPCI/1 CCSW pump mode heat removal capability. The new calculation resulted in a 77.0 MBTU/hr duty. The Hx manufacturer confirmed the new calculations using proprietary design codes. The new duty resulted in a 9% reduction in the heat removal capability from the original conditions.

The NSSS vendor recovered an unsigned letter (dated January 20, 1969) which described the 1 LPCI/1 CCSW pump analysis represented on the 1967 process diagram. The letter indicated:

- The peak SP temperature, 180°F, would be reached at 22,000 seconds after the accident.
- At 180°F SP temperature the emergency core cooling system (ECCS) pumps net positive suction head available ($NPSH_a$) was approximately equal to the net positive suction head required ($NPSH_r$) with little or no margin.
- The ECCS pump $NPSH_a$ was calculated using atmospheric pressure in the containment.

Failure to identify and take prompt corrective action when notified of the degraded Hx duty on April 6, 1992, was an apparent violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action (50-237/92034-01a(DRP)).

Licensee's Operability Evaluation

The licensee concluded CCSW system operability based on a comparison of the May-Witt decay heat model with a "realistic" decay heat model (ANSI/ANS 5.1, 1979). The realistic model predicted 15% less decay energy at point of peak SP temperature (22,000 seconds) than May-Witt. Adjusting for the 9% Hx duty degradation, the licensee concluded a 6% margin existed for post accident CHRS performance.

The NSSS vendor indicated strong evidence existed to conclude that May-Witt was used for the original containment heat removal analysis. However, conclusive documentation was not retrieved.

5. New Containment Heat Removal Analysis

The licensee completed a new DBA LOCA containment heat removal evaluation on December 1, 1992. The new analysis evaluated the following four cases:

Case	Configuration	Peak SP Temperatures	Margin to NPSH
1	2 LPCI/2 CCSW pumps[1]	168°F	9.3 ft head
2	2 LPCI/2 CCSW pumps[2]	171°F	13.4 ft head
3	1 LPCI/1 CCSW pump[1]	180°F	9.0 ft head
4	1 LPCI/1 CCSW pump[2]	186°F	14.0 ft head

[1] nominal flow rates
[2] flow rates adjusted for flow uncertainty

The 2 LPCI/2 CCSW pumps case Hx duties used corresponded to the degraded train flow conditions. The 1 LPCI/1 CCSW pump case duties used were reduced (from the original analysis) to reflect the correction of U. The ANS 5.1 (1979) decay heat model, with no uncertainty adder, and elevated torus pressure were also used in the evaluation. On December 1, 1992, the licensee completed a second SAR update to include the evaluation results and to further "clarify" the licensing bases. The accompanying safety evaluation concluded no unreviewed safety questions (USQs) existed.

6. <u>Inspectors Review of the New Containment Heat Removal Analysis</u>

The inspectors identified the following concerns and discrepancies with the new containment heat removal analysis:

- Unapproved use of ANS 5.1 (1979) decay heat model.
- Unapproved use of SHEX computer model for containment LOCA response.
- Incorrect assumptions for net positive suction head calculations.
- Incorrect assumed CCSW initiation time.

<u>Unapproved Use of ANS 5.1 (1979) Decay Heat Model</u>

ANS 5.1 (1979) decay heat model was used by the NSSS vendor for the drywell temperature (DWT), drywell pressure (DWP), and SP temperature responses for the four cases evaluated in the new analysis. The heat input predicted by ANS 5.1 (1979) was non-conservative when compared to either:

- Branch Technical Position ASB 9-2, Residual Decay Energy For Light-Water Reactors For Long-Term Cooling, Standard Review Plan, 9.2.5, Ultimate Heat Sink, or
- May-Witt model

An NRC staff position concerning the boiling water reactor (BWR) Power UPRATE Program (TAC No.79384) was issued September 30, 1991. Power

UPRATE was a proposed generic program for increasing thermal power limits. The staff approved the vendor's proposal, as described in Topical Report NEDC-31897P-1, "Generic Guidelines for General Electric Boiling Water Reactor Power Uprate" with the exception of the calculation of SP response to LOCA events. The Staff Position stated:

- The model was not approved for generic use.

- Methodology and computer codes specified in the plants SAR should continue to be used for the calculations of containment response to LOCA.

- A plant specific amendment was required before "more realistic" models could be used.

The ANS 5.1 (1979) decay heat model was used without the addition of an uncertainty adder. The NRC had approved ANS 5.1 (1979), on a plant specific amendment bases, when an uncertainty adder of 110% was used.

The licensee did not have a plant specific amendment approving the use of the ANS 5.1 (1979) model. The licensee estimated use of May-Witt would result in an additional 15°F in the peak bulk SP temperatures.

Unapproved Use of SHEX Computer Model For Containment LOCA Response

The SHEX computer model was also used for the containment heat response cases evaluated in the new analysis. The September 30, 1991, Staff Position stated the SHEX computer code was not approved for the generic use of suppression pool response to LOCA events. The position stated a plant specific amendment was required. The amendment request was to include specific justification (and confirmatory calculations for validation) for its use. No amendment was approved for Dresden.

Incorrect Net Positive Suction Head Calculations

The licensee evaluated LPCI $NPSH_a$ for the four DBA cases. Post-accident elevated torus pressures (minimum of 4 psi) were used in the calculations. This assumption contradicted the bases for TS 3.7.A.c, which restricted the initial maximum SP temperature to 95°F. TS 3.7.A.c ensured containment pressure was not required to maintain adequate NPSH for the ECCS pumps for the 2 LPCI/2 CCSW case. Also, Safety Guide 1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps" (November 2, 1970), stated the CHRS should be designed so that adequate NPSH was provided to system pumps assuming maximum expected temperatures of pump fluids and no increase of containment pressure from that present prior to postulated loss of coolant accidents.

Use of elevated containment pressure was also inconsistent with the emergency operating procedures (DEOPs). DEOP-200-1, "Primary Containment Control," directed the operating authority to initiate torus and drywell sprays before containment pressure reached 9 psig. The sprays were to remain in operation until the containment and wet-well pressures were less than 2 psig. The calculations assumed a minimum of 4 psi over pressure.

The licensee did not evaluate $NPSH_a$ bounding conditions. $NPSH_a$ was calculated only at the pressure and SP temperature state-points provided for the four cases analyzed. Actual NPSH conditions could be more limiting. Increased LPCI flow (at a constant CCSW flow, from the reduced flow state-point condition) decreases $NPSH_a$ and increases $NPSH_r$ with a minimum effect on the saturation pressure (temperature) of the SP water. Also, the calculation did not evaluate core spray (CS) NPSH. The SAR indicated CS NPSH was more limiting than LPCI.

The $NPSH_a$ calculation used $NPSH_r$ and suction piping losses from a 1984 letter used for emergency operating procedures (EOPs) development. The information provided by that letter was not verified under the Quality Assurance program requirements. Failure to evaluate the bounding conditions for NPSH that ECCS pumps would be subject to was an apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Control (50-237/92034-02a(DRP)).

The NPSH calculation appeared non-conservative by one to two Ft. The LPCI pump $NPSH_a$ was presented in "feet of head" (Ft) at the elevated torus temperatures (168°F - 186°F). However, $NPSH_r$ was determined using cold water. The licensee did not compensate for the density change affect on "Ft of head" at the elevated temperatures. The difference, when compared to psia, was proportional to the ratio of the specific volumes at the elevated temperatures. The failure to include temperature correction of the $NPSH_a$ values was considered unresolved pending further review by the NRC (Unresolved Item (237/92034-03(DRP)).

Incorrect Assumed CCSW Initiation Time

The CCSW system initiation time assumed in the analysis was inconsistent with operator training and administrative controls. The analysis assumed the CHRS, and associated Hx, was available for the removal of energy from the SP at 600 seconds after the DBA. Plant operating procedures did not specifically address when the CHRS was to be placed in service. The operating authority was trained to initiate the system between 20 and 35 minutes following the DBA. The inspectors estimated the delay would result in an additional 3°F to 4°F post DBA peak SP temperature. The inspectors communicated the concern to the licensee on January 8, 1993.

Safety Significance of Degraded CHRS

The loss of ECCS pump NPSH in the post-LOCA environment would potentially challenge the remaining two fission product barriers:

- The fuel cladding would be challenged due to overheating following the loss of CS and LPCI pumps.

- The containment would be challenged following failure of CHRS.

- The ECCS pump seals would be challenged as the SP vapor pressure approached saturation conditions.

The inspectors evaluated the ECCS pump net positive suction head margin ($NPSH_m$) using the licensee's containment pressure and SP temperature state-points. $NPSH_m$ was defined as $NPSH_a$ minus $NPSH_r$. Atmospheric pressure in containment (Ct) and the estimated elevated SP temperature conditions, if the original decay heat model was used (an additional 15°F SP temperature), were considered.

	Net Positive Suction Head Margin			
	Case 1 (Psia)	Case 2 (Psia)	Case 3 (Psia)	Case 4 (Psia)
ANS 5.1 & Ct over pressure	3.6	5.3	3.3	5.5
ANS 5.1 and 14.7 psia Ct pressure	-0.5	0.9	-1.9	-0.4
May-Witt and Ct over pressure	1.2	2.8	0.4	2.2
May-Witt and 14.7 Ct pressure	-2.8	-1.6	-4.8	-3.7

Use of the original decay heat model would have eliminated almost all NPSH margin assuming containment over pressure. Also, the evaluation concluded inadequate $NPSH_a$ when atmospheric containment pressure was assumed.

Inspectors Review of Root Cause

Based on review of available information, the inspectors concluded the following causal factors contributed to the apparent violations identified above:

- Failure to verify assumptions used by contractor personnel

- Inadequate project integration with the design bases

Previous Occurrences

A previous non-cited violation (50-237/91010-01(DRP)) of 10 CFR 50, Appendix B, Criterion III, Design Control, was issued for the failure to ensure adequate contractor review. The issue dealt with the use of non-conservative parameters and assumptions in vendor calculations associated with a diesel generator cooling water system. As corrective action, the licensee issued Engineering and Construction (ENC) procedure

QE-81, "Review of Assumptions and Judgments for Architects Engineering and Evaluations." ENC-QE-81 was to assure applicable regulatory requirements were addressed for design evaluations and an adequate review of associated assumptions was performed.

7. NRC Review of Current Licensing and Design Bases

The inspectors reviewed the updated final safety analysis report (UFSAR); the final safety analysis report (FSAR); the original and current technical specifications (TS); the original and current TS bases (TSB); and the systematic evaluation program (SEP) description of previous containment heat removal analyses. The purpose of the review was to ascertain the Dresden CHRS licensing and design bases and determine the minimum number of CCSW pumps required to mitigate DBA events.

SP DBA LOCA Temperature Response

Both the original and current TSB 3.7.A stated bulk SP temperature was expected to rise 50°F, to 145°F, immediately following the DBA LOCA blowdown. The drywell temperature (DWT) and drywell pressure (DWP) DBA responses were shown in SAR Figures 5.2.12 and 5.2.11. The curves provided the long-term (greater than 600 seconds) containment response for four cases of CHRS operation. The most limiting response was for ½ containment cooling loop and one core spray pump (case "d"). Half containment cooling loop was defined as 1 LPCI/2 CCSW pumps. However, the licensee concluded the case "d" curves represented the one CCSW pump case represented on the 1967 plant process diagram. This assumption was used in the operability evaluation described in paragraph 3 of this report.

In the SAR analysis, the SP was heated by the flow exiting from the reactor. The original DWT case "d" curve indicated a drywell temperature of 173°F at the 22,000 second point. The SAR stated the drywell temperature was taken to be 5°F hotter than the exiting flow. Therefore, the SP temperature for case "d" must have been less than 173°F. The 1967 1 LPCI/1 CCSW pump evaluation resulted in a SP temperature of 180°F at 22,000 seconds.

Comparison of the new containment heat removal analysis DWT and SP temperature data with the original DWT case "d" also confirmed the curve represented two CCSW pumps. Curve "d" plateau at 177°F between 4,000 and 10,000 seconds after the accident. At this point, the new analysis predicted SP temperature lagged DWT by 15°F to 6°F. Also at 22,000 seconds, the new analysis predicted the SP temperature would lag the DWT.

FSAR Section 6.2.3, Heat Exchangers, stated the LPCI Hxs were sized to meet the containment capability. The duty was determined by calculating the amount of heat which must be rejected from the SP, assuming HPCI operation, so that in the event of a LOCA, the terminal SP temperature would not exceed 170°F. Also FSAR Table 6.2.4 stated the Hx duty design temperature was based on 165°F.

SAR Amendment 22 addressed Advisory Committee on Reactor Safeguards concerns related to torus water contamination that may lead to an ECCS pump failure. One of the concerns addressed the failure of drywell coatings at high temperatures. The licensee's evaluation compared the failure temperature of the coatings with the maximum torus temperature of 170°F.

SEP Evaluation Report, on Topics VI-2.D and VI-3, discussed the NRC evaluation of mass energy releases for reactor coolant pipe breaks inside containment. The peak DBA SP temperature of 168°F was predicted. Also, the licensee's summary of SEP Topic V-10.A, RHR System Heat Exchanger Tube Failures, indicated the CHRS maintained the SP temperature below 170°F following a DBA.

Throughout the review, the inspectors did not identify any docketed record of a post DBA SP temperature in excess of 170°F. Additionally, the original SAR DWT response curve "d" was found to be consistent with the SAR text statements that two CCSW pumps were required. The 1967 1 LPCI/1 CCSW pump case analysis resulted in a SP temperature of 180°F. The inspectors concluded that the 1 LPCI/1 CCSW pump case was not submitted and approved by the NRC as part of the Dresden licensing or design bases.

Drywell Pressure Response

The SAR case "d" DWP response showed containment pressure decreased initially following initiation of the 1 LPCI/2 CCSW pumps. Pressure then slowly increased to the maximum due to decay energy addition to the containment. The SAR concluded the energy removal by the 1 LPCI/2 CCSW pumps and Hx was acceptable because the removal rate exceeded the addition rate from all sources. This resulted in decreasing containment pressure. SAR Figure 5.2.11 showed that long term containment pressure, greater than 600 seconds, was less than 8 psig.

Number of CCSW Pumps Required

The licensee concluded that one CCSW pump satisfied the minimum cooling requirements (as discussed in paragraph 3 of this report). This conclusion was based, in part, on the licensee's interpretation of TSB 3.5.B. TSB 3.5.B stated:

> "The containment cooling sub-system consists of two sets of two service water pumps, one heat exchanger, and two LPCI pumps. Either set of equipment is capable of performing the containment cooling function. Loss of one containment cooling service water pump or one LPCI pump does not seriously jeopardize the containment cooling capability as any two of the remaining three pumps can satisfy the containment cooling requirements. Since

there is some redundancy left, a 30 day repair period is adequate."

The licensee assumed the "any two of the remaining three pumps" referred to the remaining pumps on the CHRS train instead of the CCSW pump specific system. Therefore, the licensee believed that 1 LPCI/1 CCSW pump was sufficient.

TSB 3.5.B was revised on December 12, 1988, (amendment 107) when ECCS testing requirements were changed. The On-site and Off-site review package indicated the TSB change was to identify the equipment in each containment cooling subsystem. The original TSB 3.5.B read, in part:

> "Loss of one containment cooling service water pump does not seriously jeopardize the containment cooling capability, as any two of the remaining three pumps can satisfy the cooling requirements."

The original TSB 3.5.B clearly confirmed the two CCSW pump requirement.

The NRC concluded the acceptability of the CHRS based on a specific heat removal capability (duty). The SER, Section 3.3.5, Primary Containment Cooling System stated:

> "The containment cooling system consists of two independent and redundant spray cooling loops for post-accident heat removal. Each loop will pump water from the pressure suppression pool (torus) through individual heat exchanges (which are cooled by the service water system) and the spray headers located in the containment drywell. The water spray from the headers removes the heat from the drywell atmosphere and flows by gravity back to the torus. The heat removal capacity for each heat exchanger is 102 MBTU/hr at a river temperature of 95°F, which is adequate to prevent overheating of the torus water following a design basis accident. We conclude that this system is acceptable."

Previous NRC CHRS Concerns

SEP Evaluation Report on Topics VI-2.D and VI-3 discussed an evaluation of the DBA LOCA analyses submitted by the licensee. The NRC concluded the analysis results were within design limits. In addition to the docket review, the NRC performed a confirmatory containment pressure and heat removal analysis using modern assumptions. The review compared the Dresden configuration with the criteria used for the licensing of new facilities (General Design Criteria (GDC) 16, Containment Design, GDC 38, Containment Heat Removal, GDC 50, Containment Design Bases and NUREG 800, Standard Review Plan, Section 6.2.1, Containment Functional Design).

The confirmatory analysis used 102 MBTU/hr LPCI Hx duty and 7,000 gpm CCSW flow (2 pumps). The NRC requested that the licensee respond within 30 days if the as-built facility differed from the licensing or design basis assumed in the assessment (December 28, 1981). The NRC stated the evaluation would be a basic input to the integrated safety assessment unless the licensee identified changes to reflect the as-built conditions of the facility. The NRC stated the assessment could be revised in the future if the design was changed or if NRC criteria was modified.

Unreviewed Safety Questions

NRC acceptance of the CHRS was based on a duty of 102 MBTU/Hr at a river temperature of 95°F. The heat removal requirements were correctly translated into system design criteria which specified the Hx duty of at least that to match the assumption in the heat removal analysis. The CHRS specific function was the capability of removing 102 MBTU/Hr from the containment in the post-accident environment. To assure the heat removal capability, 7,000 gpm CCSW flow was specified as a design criteria. The validity of the safety analysis assumption of 7,000 gpm CCSW flow was maintained by TS 3.5.B, which required a minimum of two CCSW pumps, at 3500 gpm each, available during reactor operation.

The licensee changed the plant design, as described in the SAR, by reducing the minimum number of CCSW pumps from two to one, and by reducing the CCSW train flow from 7,000 gpm to 5,600 gpm. The change reduced the margin of safety as defined in the bases for TS 3.5.B and 3.7.A.c.

- The resulting 1 LPCI/1 CCSW case containment analysis indicated the long term containment pressure exceeded 8 psig. This reduced the margin of safety as defined in the bases for TS 3.5.B.

- The change reduced the Hx capacity below the value stated in the SER as a basis for approving the containment cooling system.

- The change reduced the number of CCSW pumps required to less than two. This reduced the margin of safety as defined in the bases for TS 3.5.B.

- The change reduced containment cooling (due to the reduced CCSW flow) to the point containment over pressure was required to demonstrate ECCS pump NPSH for the 2 LPCI/2 CCSW pump cases. This reduced the margin of safety as defined in the bases for TS 3.7.A.c.

- The change resulted in the SAR post DBA LOCA containment pressure and temperature response curves to be exceeded.

- The change was based on an unapproved computer code for the calculation of SP response to LOCA (SHEX) and an unapproved decay heat model. This reduced the margin of safety as defined in the bases for TS 3.5.B.

Failure of the licensee to obtain prior NRC approval for the SAR changes was an apparent violation of 10 CFR 50.59 (237/92034-04a(DRP)).

Licensee's Safety Evaluation Program

The licensee's 10 CFR 50.59 safety evaluation program defined the "margin of safety" for the bases of any technical specification as that margin between the acceptance limit and the failure point of a particular parameter or component. The licensee's acceptance limit for the new containment heat removal analysis was the design limit for primary containment (62 psig). The licensee defined the margin of safety as the margin between the design limit and failure point. The failure point was some unknown value where the containment would fail from over pressure (estimated to be about 130 psig). The licensee's program would have allowed the change provided the resultant pressure did not exceed 62 psig.

The inspectors concluded the licensee's program for determining a reduction in the margin of safety was inadequate. The TSB should be used to the maximum extent practical, when the margin of safety is explicitly defined or addressed therein. When the bases do not define the margin of safety, the SAR, the SER, and other licensing bases documents should be reviewed.

The margin could be implicit rather than explicitly expressed as a numerical value. Implicit margins are conditions for NRC acceptance, such as for computer codes, methods, industry acceptance practice or penalties. It may be sufficient to determine only the direction of the margin change. If the margin is reduced, the change may involve an USQ. The margin of safety defined in the bases section of the TS may depend on a parameter other than the process variables.

The TS were provided to ensure the plant operated in a manner to ensure acceptable levels of protection for the health and safety of the public. The TS ensured that the available equipment and initial conditions meet the assumptions in the accident analysis. The TS were not meant to be all inclusive. They are reserved for those matters where the imposition of rigid conditions, limitations upon reactor operation was deemed necessary to avoid an abnormal event or give rise to an immediate threat to public health and safety.

Previous NRC Concerns Regarding the Licensee's 10 CFR 50.59 Program

The NRC held a working meeting in the Region III offices on March 30, 1992, with the licensee and Nuclear Reactor Regulation (NRR) concerning how SER values should be treated in safety evaluations. The meeting was the result of previous NRC concerns associated with the licensee's safety evaluation program, specifically related to how calculation assumptions were used in the control room habitability analysis. The NRC concluded the change did not constitute a USQ because the licensee failed to update the SAR with the SER (Unresolved Item 90022-02 & Inspection Reports 91039 and 92005).

The NRC identified a previous USQ (Violation 50-237/90022-01(DRP)), concerning the practice of using a sample pump for containment air samples. The modification reduced the margin of safety as defined in the basis of the TS in regard to the maximum allowable primary containment accident leak rate.

The NRC previously identified two inadequate safety evaluations (Violations 50-237/91016-01(DRP) and 50/237/90022-01(DRP)). In both cases the licensee failed to consider the probability of a malfunction of equipment important to safety in a safety evaluation. The cause of both violations was a failure of licensee personnel to recognize the need to review the SEP commitments.

Inspectors Review of Root Cause

Based on review of available information, the inspectors concluded the following causal factors contributed to the apparent violation identified above:

- Failure to adequately review the licensing bases, including the SEP Topics.
- Failure to verify assumptions provided by the NSSS Vendor.
- Failure to understand the definition of the margin of safety for the bases of a technical specification.

8. CCSW System Flow Performance

The Unit 2 CCSW pre-operational test verified greater than 7,000 gpm train flow based on the pumps' discharge pressure and pump curve. A test deficiency was recorded concerning the flow indicator. The Unit 3 Pre-operational test did not verify either the one or two CCSW pump flow.

Based on the review of available information, the two pump degraded flow condition appeared to be the result of excessive pipe flow resistance and increased demand. The following contributed to the flow changes:

- Installation of the CCSW submergence protection vaults in the late 1970s. The modification diverted flow to the vault coolers and changed the piping configuration. The TS discharge pressure was reduced from 198 psig to 180 psig.
- Potential fouling by mud, silt, and biological fouling.
- The 14 inch Hx discharge piping incorporated a 12 inch motor operated valve (1501-3A/B) with a high friction coefficient (Cv).

- The flow measuring orifices were undersized and caused excessive system head loss. All four of the orifices were installed backwards.

The licensee did not have any records indicating the CCSW train flow had been verified since initial plant start-up. The licensee did not verify the train flow on Unit 2 after the Unit 3 degraded condition was identified in April 1992. Failure to incorporate an adequate test program to ensure the CCSW components performed satisfactorily, in accordance with the design requirements, was considered an apparent violation of 10 CFR 50, Appendix B, Criterion XI, Test Controls (237/92034-05a (DRP)).

Failure of the licensee to take prompt corrective action to correct the CCSW degraded flow conditions was considered an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action (50-237/92034-01b(DRP)).

<u>Prior Opportunity:</u>

The licensee had a reasonable opportunity to identify the flow degradation. Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," alerted licensees to degraded service water flow conditions. GL 89-13, Item II, discussed a test program to ensure Hx duties. However, the licensee elected periodic cleaning of the LPCI Hxs rather than performing a test program. GL 89-13, Item V, required review of operating and emergency procedures. The licensee review did not identify the degraded flow condition or the inconsistencies in the SAR.

9. <u>Emergency Diesel Generator Loading</u>

The SAR electric description was inconsistent with the accident analysis. The original containment cooling analysis was based on a minimum of two CCSW pumps. The EDG loading table reflected sufficient margin for two CCSW pump operation following a DBA. However, a "note" next to the description of the second CCSW pump stated: "if within capability of the diesel generator." Also, the SAR discussion indicated the operator could manually stop one LPCI pump and start a CCSW pump after a period not exceeding two hours.

The existing EDG load study evaluated one CCSW pump on the EDG supplied busses during DBA LOCA conditions. DOP 1500-02, "Torus Water Cooling Mode of Low Pressure Coolant Injection System," directed operations personnel to load a second CCSW pump on the safety related bus if sufficient capacity was available. However, Calculation 7317-33-19-3, "EDG Loading Under DBA Conditions," Revision 7, only reflected one CCSW pump in operation.

The inspectors identified potential margin for the second CCSW pump to be powered from the EDG on December 10, 1992. The licensee confirmed the EDG would support two pumps on January 8, 1993, after an evaluation of the pump starting currents and running loads. Failure to assure applicable regulatory requirements and the design bases were correctly translated into specifications, drawings, procedures, and instructions was considered an apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Control (50-237/92034-02b (DRP)).

The loading calculation indicated bus voltages dropped to less than 55% during LPCI pump start. However, the TS value for the undervoltage relays was 70% (±5%). The estimated steady state load only provided 0.5% margin to rated capacity. These issues will be considered unresolved pending a detailed review of the loading calculation (Unresolved Item 237/92034-06 (DRS)).

10. <u>LPCI Hx Tube Replacement</u>

Beginning in 1989, the 70-30 Cu-Ni LPCI Hx tubes were replaced with AL-6X (stainless steel) following failure. Less than 6% of the tubes have been replaced. The modification safety evaluation concluded the change did not constitute a USQ. The SAR was changed to reflect replacement of all the tubes. The material change-out reduced the Hx duty from 105 MBTUs/hr to 95 MBTUs/hr assuming 7,000 gpm CCSW flow.

The licensee performed a SP temperature response analysis to model a small break LOCA (isolation condenser steam line break) with manual depressurization and one CHRS train available (2 LPCI/2 CCSW pumps). The safety evaluation indicated the event yielded the highest bulk pool SP temperatures among those cases analyzed in the Mark I Long-Term Program.

The licensee used a non-approved decay heat model in the analysis. The model was a derivation of decay heat based on ANS 5.1 (1979). The derivation employed a low 183.6 MEV/fission value and a 2% uncertainty adder. The derivation was non-conservative when compared to either:

- Branch Technical Position ASB 9-2
- May-Witt

Neither the Hx tube replacement safety evaluation or the analysis addressed the modifications effect on the following:

- The reduction of CHRS capacity in the DBA LOCA analysis.
- The magnitude or the consequence of the increased DBA containment pressure and temperature response due to the reduction in Hx duty.
- The effect of higher DBA SP temperatures on ECCS pump NPSH, piping, or seals.

The SAR change indicated the Hx duty was reduced below the SER acceptance value for the CHRS. The failure to perform a bounding analysis and adequate review was considered an apparent violation of 10 CFR 50.59 (50-237/92034-04b(DRP)).

The Mark I Long-Term Program analysis took credit for the availability of offsite power and a peak local temperature limit of 205°F. The UFSAR, Section 5.2.3.9.27, "Plant Unique Analysis (PUA) Results," stated all of the applicable Mark 1 criteria were met. However, Safety Evaluation Report, "Mark 1 Containment Long-Term Program," NUREG-0661, Supplement 1, stated the local SP temperature shall not exceed 200°F and NUREG-0783, "Suppression Pool Temperature Limits for BWR Containments," required that off-site power be assumed not available (except for feed water pumps). The Dresden specific SER (September 18, 1985) did not indicate NRC approval for the exceptions. This issue was considered unresolved pending further NRC review of the PUA (Unresolved Item 50-237/92034-07(DRP)).

11. Reporting Requirements

On April 2, 1992, operations personnel identified significant degradation of Unit 3 CCSW flow as discussed in paragraph 3 of this report. The licensee assumed the degraded condition also occurred on Unit 2. Unit 2 was operating and Unit 3 was in refuel mode at the time of discovery. 10 CFR 50.72 (b)(2) required the NRC be notified within four hours of occurrence of any event found when the reactor is shutdown, that, had it been found when the reactor was in operation would have resulted in a principle safety barrier being seriously degraded or in an unanalyzed condition that significantly compromised plant safety. For the operating unit, 10 CFR 50.72 required the NRC be notified within one hour of the occurrence of any event or condition that resulted in a condition outside the design bases of the plant. Also, 10 CFR 50.73 (a)(2)(ii)(B) required the licensee to submit a licensee event report (LER) for any condition that resulted in the plant being in a condition outside of the design bases. The failure to make the required NRC notifications was considered an apparent violation of 10 CFR 50.72 and 50.73 (50-237/92034-08a(DRP)).

On May 14, 1992, with Unit 2 operating and Unit 3 shutdown, the licensee was informed the LPCI Hx duty was degraded 9% from what was believed to have been used in the limiting case accident analysis. Based on the information available, this was a condition outside the design bases of the plant. The licensee did not initiate a condition adverse to quality report (CAQR), report the event to the NRC within one hour of discovery, or submit a LER within 30 days. This was considered an apparent violation of 10 CFR 50.72 and 50.73 (50-237/92034-08b(DRP)).

On December 15, 1992, with Unit 3 operating, the licensee was informed the decay heat model and computer method used in the limiting CHRS accident analysis was non-conservative and un-approved for use. This was a condition outside the design bases of the plant. The licensee did not initiate a CAQR, report the event within one hour of discovery to the NRC, or submitted a LER within 30 days. This was considered an apparent violation of 10 CFR 50.72 and 50.73 (50-237/92034-08c(DRP)).

On January 8, 1993, with both units operating, the licensee was informed of a 20 minute difference between the assumed CHRS initiation time used in the accident analysis and the CCSW starting time expected from operator training. This was a condition outside the design bases of the plant and not covered by the plants operating or emergency procedures. The licensee did not initiate a CAQR or report the event within one hour of discovery to the NRC. This was also considered an apparent violation of 10 CFR 50.72 (50-237/92034-08d(DRP)).

10 CFR Part 21 required, in part, that each entity subject to the regulation of this part, adopt appropriate procedures to provide for evaluating deviations. A deviation was defined as a departure from the technical requirements of a procurement document. A Part 21 basic component included safety related design, analysis, and consulting services. The licensee determined the following non-compliances did not require a Part 21 deviation evaluation:

- Discovery of the contractor supplied degraded LPCI Hx duty (May 13, 1992)

- Discovery the decay heat model and computer method used in a contractor supplied limiting CHRS accident analysis was non-conservative and un-approved for use (December 15, 1992)

This issue was considered unresolved pending NRC review of the procurement documentation associated with both activities (Unresolved Item 50-237/92034-09(DRP)).

Previous NRC Reporting Concerns

Within the past two years, five violations with numerous examples were cited for the failure to meet 10 CFR 50.72 and 10 CFR 21 reporting requirements. Violation 237/91016-03 was issued for the failure to make a 50.72 report on January 16, 1991, when it was known that the material toughness for the reactor studs were outside FSAR allowable. The licensee incorrectly concluded the condition was not a significant degradation. Violation 237/90027-06 was issued for the failure to make 50.72 report following an ESF actuation on December 8, 1990. Corrective actions were inadequate and resulted in another missed notification in July 1991. Violation 237/91022-10 was cited for inadequate corrective actions. The corrective actions to violation 91022-10 proved to be inadequate also as two additional ESF actuations were not reported in March and April 1992. Violation 92009-05c was cited for the inadequate corrective actions.

Violation 237/92009-02 was cited for an inadequate 10 CFR 21 screening procedure which failed to recognize consulting services discrepancies, resulting in a defect, as reportable. The licensee failed to report a defect associated with the VOTES program. The procedure was revised to include more specific guidance.

In addition, a letter to Mr. Cordell Reed, Senior Vice President CECo., from Mr. Edward Greenman, Director, Division of Reactor Projects, Region III, dated October 4, 1991, clarified the NRC position. The letter stated that use of engineering judgment differed significantly between reportability and operability determinations. Reportability determinations needed to consider short and long term operability, generic implications, and the importance of the components. To accomplish this, sufficient information for a correct reportability determination was required for the licensed operations staff. Operability determinations shall be prompt commensurate with the potential safety significance of the issue.

12. <u>CCSW Intertie to the Main Control Room Habitability Refrigeration Unit</u>

CCSW provided safety related cooling to the only control room emergency heating, ventilation and air conditioning (HVAC) air handling unit (AHU). The normal emergency HVAC cooling source was the non-safety related service water system (SWS). An interconnecting 2½" branch line allowed any of the four Unit 2 CCSW pumps to supply cooling water to the emergency HVAC system by use of a number of manual valves and one air operated supply valve. Upon loss of instrument air the SWS valve failed closed while the CCSW supply valve failed open.

<u>Problem Occurrence</u>

During the HVAC system design, in 1982, the licensee's contractor indicated a CCSW pump could probably deliver the 120 gpm to the control room air conditioning system with a negligible decrease of flow to the LPCI Hxs. Modification M12-2/3-82-1 installed the new HVAC system including the CCSW branch line in 1984. The post modification test, completed on January 3, 1985, acceptance criteria was based exclusively upon receiving the minimum flow (120 gpm) through the HVAC's air handling unit. Testing did not evaluate the effect of system interactions on CCSW.

<u>Problem Identification</u>

In October 1992 the Illinois Department of Nuclear Safety inspector questioned the effect of the HVAC branch line on CCSW flow performance. A CAQR was generated and on October 28, 1992, the licensee's evaluation concluded the CCSW system was operable. The licensee estimated a 3 psid drop at the CCSW pump discharge due to the HVAC branch line. However, testing completed on November 18, 1992, reflected much larger pressure drops of 4 to 11 psid. The B and C pumps were declared inoperable since discharge pressure was only 175 and 177.5 psig respectively. After flow balancing the vault coolers and the HVAC line, the required discharge pressure was achieved and the pumps declared operable.

Problem Consequences

The inspectors reviewed historical surveillance test data taken between 1990 and 1992, and noted several instances where CCSW pump performance was near the limit for required pressure and flow. After subtracting the pressure drop (4 to 11 psi) caused by the HVAC branch line, the TS requirements of 3500 gpm at 180 psi would not have been met.

Although the CCSW system was degraded by the reduced discharge pressure the safety significant attributes, pump discharge flow and Hx pressure drop, were still met. The 180 psi assured a 20 psid across the LPCI Hx tubes. The LPCI system discharge pressure was on the order of 110 psi. Therefore, the 20 psid was still maintained.

Failure to assure the CCSW test surveillance demonstrated the system performed satisfactorily, was an apparent violation of 10 CFR 50, Appendix B, Criterion XI, Test Control (50-237/92034-05b(DRP)).

Inspectors Review of Root Cause

Based on review of available information, the inspectors concluded the following causal factors contributed to the apparent violations identified above:

- The original hydraulic evaluation of the branch line failed to quantify the CCSW pressure drop.
- Post modification testing did not validate the engineering assumptions used in accepting the CCSW supply to the HVAC.
- The periodic surveillance tests on CCSW pumps were inadequate to ascertain the true performance capability of the CCSW system during a design basis event.
- The safety evaluation performed for the modification failed to identify the reduction of the margin to safety provided by the bases for TS 3/4.5.B.

Potential for Licensee Identification of the Problem

The licensee had a reasonable opportunity to identify the problem. In 1988 the NRC issued Generic Letter (GL) 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment." GL 88-14 required verification that,following a loss of the instrument air system, safety-related equipment would perform as intended. The internal review and response to the NRC on November 7, 1990, did not detect the problem. Had a more thorough evaluation of the consequences of failing "open" the safety related HVAC supply valve and closure of the non-safety related supply valve been performed, the consequences on CCSW could have been identified.

13. Information Meetings

On January 15, 1993, a working level meeting was held at Dresden Station to discuss the safety significance and compliance issues concerning the degraded CCSW system. At that meeting the licensee presented the safety evaluation philosophy as discussed in paragraph 7 of this report. On January 27, 1993, a second information meeting was held at the NRC Region III office to discuss ECCS pump NPSH calculations and limitations.

14. Licensee Event Reports Followup (92700)

(Closed) LER 237/92038 and Revision 1, Containment Cooling Service Water found Outside Technical Specification Limits due to an Inadequate Systems Interaction Analysis.

15. Licensee Action on Previously Identified Items (92701)

(Closed) Unresolved Item 237/92005-06(DRP), Previous unresolved item concerning the degraded CCSW train flow discussed in paragraphs 2, 3, 4, 5, and 6 of this report.

16. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during the inspection are discussed in Paragraphs 6, 9, 10, and 11.

17. Exit Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) during the inspection period and at the conclusion of the inspection period on January 29, 1993. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.