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OFFICE OF NUCLEAR REACTOR REGULATION

Division of Reactor Inspection and Safeguards

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Licensee: Nebraska Public Power District
P.O. Box 499
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Inspection At: Cooper Nuclear Station
Brownville, NE

Inspection Conducted: June 27 through July 15, 1988

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1.0 INSPECTION SCOPE

The inspection was performed to verify: that the Cooper Nuclear Station (CNS) emergency operating procedures (EOPs) were technically accurate; that their specified actions could be physically carried out in the plant using existing equipment, instrumentation, and controls; and that the plant staff could correctly perform the procedures. The inspection was conducted in accordance with the guidance in Temporary Instruction (TI) 2515/92, "Emergency Operating Procedures Team Inspections."

2.0 BACKGROUND

Following the Three Mile Island (TMI) accident, the Office of Nuclear Reactor Regulation developed the "TMI Action Plan" (NUREG-0660 and NUREG-0737), which required licensees of operating plants to reanalyze transients and accidents and to upgrade emergency operating procedures (EOPs) (Item I.C.1). The plan also required the NRC staff to develop a long-term plan that integrated and expanded efforts in the writing, reviewing, and monitoring of plant procedures (Item I.C.9). NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," represents the NRC staff's long-term program for upgrading EOPs and describes the use of a procedure generation package to prepare EOPs.

The licensees formed four vendor owners' groups corresponding to the four major reactor types in the United States; Westinghouse, General Electric (GE), Babcock and Wilcox, and Combustion Engineering. Working with the vendor company and the NRC, these owners' groups developed generic procedures that set forth the desired accident mitigation strategy. For GE plants, the generic guidelines are referred to as emergency procedure guidelines (EPGs). These EPGs were to be used by licensees in developing their procedure generation package (PGP). Submittal of the PGP was made a requirement by Confirmatory Order dated June 15, 1984. Generic Letter 82-33, "Supplement 1 to NUREG 0737 - Requirements for Emergency Response Capability," required each licensee to submit to the NRC a PGP that included:

(1) Plant specific technical guidelines (PSTGs) with justification for safety-significant differences from the EPGs

(2) a plant specific writer's guide (PSWG)

(3) a description of the program to be used for the verification and validation of the EOPs

(4) a description of the training program for the upgraded EOPs.

The licensees were to develop plant-specific EOPs that would provide the operators with directions for mitigating the consequences of a broad range of accidents and multiple-equipment failures.

For various reasons, there were long delays in obtaining NRC approval of many of the PGPs. Nevertheless, the licensees have all implemented their EOPs. To determine the success of this implementation, a series of NRC inspections are being performed to examine the final product of the program: the EOPs. A representative sample of each of the four vendor types has been selected for review by four inspection teams from Regions I, II, III, and IV.

An additional 13 inspections, including this one at CNS, are being performed at facilities with General Electric Mark I-type containments. The latter inspections are being conducted by the Office of Nuclear Reactor Regulation and include a detailed review of the containment venting provisions of the EOPs.

3.0 DETAILED INSPECTION FINDINGS

3.1 Program and Procedure Review

Documents reviewed during the inspection are listed in Attachment B.

3.1.1 Comparison of Owners' Group (OG) Emergency Procedure Guideline With CNS EOPs

The inspection team reviewed the owners' group emergency procedure guidelines (OG EPGs) and compared them with the CNS plant-specific technical guidelines (PSTGs). The PSTGs at CNS were identified as the CNS EPGs. The review was conducted to identify any technical deviations between the OG EPGs and CNS EPGs and to determine the adequacy of the licensee's documentation and justification for any technical deviations. Observations made by the team during the review included:

(1) The licensee did not submit the PSTGs as part of the procedures generation package to the NRC for review as required by NUREG-0737, Supplement 1, Item 7.2.b. This omission appeared to be significant because the licensee in developing the emergency operating procedures (EOPs) deviated in several instances from the NRC-approved OG EPGs without providing adequate documented justification. This led to the implementation of the CNS EOPs without a formal safety evaluation.

Revision 3 of the OG EPGs had been approved in an NRC safety evaluation report and was intended by the NRC to form the basis for the development of the PSTGs. Documentation provided by the licensee indicated that the NRC safety evaluation report would have been sufficient had the OG EPGs, Revision 3, been used exclusively for developing the CNS EOPs. However, the licensee used draft OG EPGs, Revision 3I, to develop the plant-specific procedures. Revision 3I contained technical differences from Revision 3, which, as a minimum, should have been subjected to a site specific safety evaluation. Examples of these technical differences included:

- In EOP-1, Contingency 6, Step C6-3.2, a phrase was added to maintain the pressure of the reactor pressure vessel as low as practical by throttling injection due to nil ductility transition temperature considerations.
- Reactor flow stagnation power was deleted from the CNS EPGs.
- The CNS EPGs included flow stagnation water level resulting from deletion of the reactor flow stagnation power.
- The step on filling reference legs was deleted from the CNS EPGs.
- The CNS EPGs allowed intermittent use of residual heat removal pumps for purposes other than low pressure coolant injection mode operation.

The licensee told the team that it had asked the NRC staff how it was to justify a plant-specific safety evaluation in that some of the operations required by the EOPs placed the plant outside technical specification requirements. The licensee provided a telephone conversation record memorandum that documented an informal NRC staff position indicating that a formal licensee safety evaluation was not required because the NRC staff had performed and documented a generic safety evaluation of the OG EPG, Revision 3.

The team concluded that a plant-specific safety evaluation should have been performed on the plant-specific data used for the EOPs and for future revisions to the plant-specific procedures generation package and EOPs. The licensee stated that the need for additional evaluation and justification of the deviations from the OG EPGs, Revision 3, was under review. Pending further NRC review of the licensee's review of additional evaluation and justification, this is an unresolved item (298/88200-01).

(2) The team determined that the licensee's method of calculating drywell temperature used as the entry condition (drywell temperature control (DW/T)) for EOP-2 did not strictly adhere to the method recommended in the OG EPGs. The licensee developed the value for the entry-condition temperature by selecting temperature monitors (TE-505 series instruments) in the vicinity of the reactor pressure vessel level instrument reference legs and safety relief valves as recommended by the EPGs. The temperature data for the instruments for the past four years were then reviewed, the highest value observed (171°F) was selected, a 10-percent margin was added, and a rounded value of 185°F was assigned as the EOP-2 entry condition.

The OG EPGs recommended using the maximum normal operating temperature, if there was no drywell temperature technical specification limiting condition for operation, as the entry condition, not the highest observed temperature, as was apparently done. The team observed the entry-condition instruments during near-peak summer-heat conditions and found that the nominal average temperatures were in the 155°-160°F range. The team noted that the licensee's method of determining the entry-level temperature resulted in a higher than warranted entry-condition temperature. Discussions with the licensee indicated that it believed that its method was in accordance with the OG EPGs; therefore, it had not developed a technical justification for the apparent deviation from the recommendation in the OG EPG to justify the method used.

The team further noted that in the CNS Updated Safety Analysis Report Chapters 7 and 14, a bulk (volumetric) average containment temperature of 135°F was used as the initial condition for various accident analyses and that the same temperature was used as an input for the calculation of various EOP limits and curves. The licensee had not determined actual bulk average temperature for comparison with this temperature. The licensee performed a special calculation during the inspection that showed that the actual bulk average temperature was acceptable.

The EOP entry-condition temperature of 185°F, however, implied that containment temperature would increase by about 30 degrees over that observed during this inspection before emergency actions would be implemented. The licensee was asked to correlate the change in "nominal" bulk average containment temperature with the EOP entry condition to demonstrate that the rise in containment temperature before emergency actions were implemented would not adversely affect either the containment response to analyzed accidents or the EOP limits. Section 3.1.3 of this report discusses this entry-condition temperature as it relates to the EOPs.

At the close of the inspection, the licensee was continuing to evaluate the above. At the exit meeting for this inspection on July 12, 1988, the licensee told the team that preliminary information from the nuclear steam supply system vendor indicated that the effect on containment response to accidents appeared negligible (GE letter from J. Torbeck to K. Walden, July 11, 1988). This letter, however, noted only that an increase in containment temperature from 135° to 150°F would have a negligible effect on the maximum pressure and temperature and the dynamic loads calculated during a loss-of-coolant accident and did not address the other correlation concerns discussed above.

The licensee was performing additional analyses to justify increasing the average design temperature from 135° to 150°F and had initiated a work request to establish a method for periodically determining actual bulk average temperature. The licensee planned additional analyses to correlate the rise in average design temperature with the 185°F entry condition. Pending licensee resolution of the adequacy of the method used to determine the entry level temperature of 185°F, this is an unresolved item (298/88200-02).

(3) The OG EPGs listed seven systems that could be used as alternative means for injecting boron into the reactor should the standby liquid control system fail. The plant-specific "step deviation documentation," which justified deviations between the OG EPGs and the CNS EPGs, did not identify a deviation, although the licensee elected to use only one alternate flow path via the reactor water cleanup (RWCU) system.

The team questioned the availability of the RWCU system during a loss of offsite power in that the system components were not powered from the critical (vital) buses during a loss of offsite power. The licensee stated that the use of the reactor core isolation cooling system (as recommended by the BWROG EPGs) was under review to determine an additional boron injection method. The licensee planned to document the reasons for not using the other injection flow paths recommended by the OG EPGs. Pending the completion of this documentation, this is an unresolved item (298/88200-03).

(4) GE Drawing No. 76-950, "EOP Flow Diagram," was referred to in the EOPs but was not available for use at the time of this inspection because it was being revised to reflect the changes made by Revision 4 to the EOPs (issued June 2, 1988).

Section II.B of Emergency Procedure (EP) 5.8, "Emergency Operating Procedures," Revision 4, stated that the flow charts provided a quick overall view of the actions the operator was expected to take and could be used by the station shift technical advisor or management to follow the EOPs and that the flow charts showed the interrelationships between the procedures, as the EOPs addressed the entire plant.

The team felt that the flow charts could be a valuable tool to help with placekeeping and that not having them available for the use indicated in EP 5.8 could detract from the response to an event. The licensee stated that work on the revisions to the flow charts had been expedited and was expected to be completed within about a month.

3.1.2 Quality Assurance for the Plant-Specific Emergency Procedure Guidelines

NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," Section 4.4, "Quality Assurance," states that the plant-specific technical guidelines (emergency procedure guidelines, EPGs) should be subject to examination under the plant's overall quality assurance (QA) program to ensure that they are accurate and up to date.

The initial CNS EPGs and associated calculations were not controlled under the licensee's QA program, although the EOPs themselves were. The licensee stated that the CNS EPGs and associated calculations and bases were developed about 1982-84 and were not subject to the QA program that existed at that time.

The team reviewed the current administrative and QA program procedures for applicability of the QA program provisions to the EOP program. Procedures reviewed included:

- "NPPD QA Program for Operation Policy Document," Revision 4

- Administrative Procedure 0.4.1, "Controlled Documents Other Than CNS Procedures and Vendor Manuals," Revision 0

- Administrative Procedure 0.22, "Preparation, Review, and Approval of Emergency Operating Procedure Changes," Revision 2.

These documents did not include QA requirements for the following:

- configuration control and design verification of the plant-specific EPGs and associated calculations and input data

- formal document control provisions for plant-specific EPG elements

- control of EPG documents as QA records.

Except for final calculations performed by the nuclear steam supply system (NSSS) vendor under the vendor's QA program, no formal controls were described in the licensee's procedures. The licensee had applied informal controls to the program that included independent verification by the licensee of NSSS vendor calculations, informal peer review and supervisory approval, and orderly maintenance of original copy records. These activities provided some assurance of program integrity.

The licensee acknowledged the above and indicated that QA requirements would be evaluated and applied as appropriate to the next revision of the procedures generation package.

3.1.3 EOP Calculations

The owners' group emergency procedure guidelines (OG EPGs) included a number of plant-specific limits, setpoints, and action levels that required calculation of plant-unique values. Appendix C of the EPGs provided detailed directions for developing input data and performing these calculations. The team reviewed a sample of the input data development and final calculations for CNS.

EPG, Appendix C, Table C1-T4, "Plant-Data," required separate development and calculation of plant-specific values for use as input data for the emergency operating procedure (EOP) limit, setpoint, and action-level calculations and curves. The licensee had contracted with the NSSS vendor to perform these calculations. The team reviewed the calculations and source data for Table C1-T4 developed by the vendor in 1983-84. Specific calculations reviewed in part or in whole included:

- reactor pressure vessel water volumes
- reactor pressure vessel water masses
- drywell volumes, pressures, and equipment elevations
- suppression pool volumes, pressures and equipment elevations
- downcomer volumes, pressures, and equipment elevations.

In general, these calculations were very informal. They were performed on plain paper with no identification of the performer and no evidence of review by the performing organization. Typically, the calculations did not include the purpose, date of performance, output requirements, source of the calculation methodology, or documentation of calculation checking and contained only a limited description of input assumptions and input data sources.

The Table C1-T4 calculations and results had been independently verified by the licensee, and verification was documented by initials or signatures on the individual calculations. The licensee had identified and resolved a number of discrepancies in the vendor calculations. The team interviewed personnel involved in this verification and found that, notwithstanding the lack of engineering discipline in the presentation of the calculations by the vendor, the licensee's review was effective in verifying their validity and identifying and resolving discrepancies.

The licensee acknowledged the above and stated that the calculations had been performed before the implementation of current, more rigorous, QA controls for such activities. The licensee was preparing for implementation of Revision 4 of the OG EPGs and stated that this effort would be subject to more rigorous controls.

The team also reviewed a sample of calculations, design verification and discrepancy resolution documentation, and related correspondence for the final Appendix C calculations listed below.

- EOP Figures 1-1 and 1-2, low pressure coolant injection (LPCI) and core spray net positive suction head curves

- conversion of suppression pool pressure to drywell pressure

- EOP Figure 2-3, "Drywell Spray Initiation Pressure Limit"

- EOP Figure 2-4, "Pressure Suppression Pressure"

- EOP Figure 2-5, "Primary Containment Design Pressure"

- EOP Figure 2-6, "Primary Containment Pressure Limit"

- drywell spray flow rate

- suppression pool cooling spray initiation pressure (SPCSIP).

The team verified the correlation of input data from Table C1-T4, performed checking calculations, and confirmed to the extent possible that the calculations had been performed in accordance with the Appendix C procedures. The team noted that these vendor-performed calculations included input assumptions, bases, and the identification of the performer and checker.

As discussed in Section 3.1.1 of this report, the team identified a concern regarding the design-basis, average drywell temperature of 135°F, which was used as the basis for the accident analysis in the CNS Updated Safety Analysis Report and as an input to the EOP calculations for drywell spray flow rate, SPCSIP, and EOP Figure 2-4 (above). EOP-2, "Primary Containment Control," specified an entry condition of 185°F drywell temperature. The licensee was unable to correlate this entry condition temperature with the actual drywell temperature at the beginning of the accident and the average design temperature value of 135°F.

The licensee had not evaluated the effects that the elevated drywell temperatures might have on plant performance at the time of EOP entry. As part of the evaluation of this latter issue, the team performed sensitivity calculations for SPCSIP and EOP Figure 2-4, using all original vendor input data except that drywell temperature was varied over the range of 135° to 165°F. These calculations showed that the effect of drywell temperature on SPCSIP was probably negligible but that the effect on the pressure suppression pressure curve of Figure 2-4 was potentially significant (2- to 4-percent nonconservative) in the range of normal suppression pool levels. This was discussed with the licensee who stated that the containment temperature considerations were under evaluation and their effect on EOP limits and curves would also be considered. The licensee further stated that a revision to the existing EOPs was being developed in accordance with Revision 4 to the OG EPGs and that Revision 4 appeared to address this concern by specifying the use of either maximum or minimum drywell temperature (DW/T) values based on which was most conservative for the specific calculation rather than an average.

3.2 Containment Venting

The team reviewed the provisions in EOP-2 and Emergency Procedure (EP) 5.3.7, "Post Accident Venting of Primary Containment," Revision 2, for conformance with the owners' group emergency procedure guidelines (OG EPGs), acceptability of the engineering bases for the procedures, and the ability of the operators to implement the procedures during walkthrough scenarios. EOP-2 required initial venting of the containment (within technical specification radioactive release limits) when drywell pressure reached 2 psig. Emergency venting was required, without consideration of containment temperature or radiation releases, when containment pressure approached the primary containment design pressure.

EP 5.3.7 was issued in July 1987 and provided instructions for the use of a single vent path from the containment drywell through small-bore (1-inch) valves and piping to the standby gas treatment system. The procedure did not provide for other backup or prioritized flow paths, nor did it include specific instructions for monitoring radiation release concentrations or assessing offsite doses. Radioactive discharge and dose assessment considerations were, however, briefly addressed in the discussion section of the procedure.

The licensee had been studying other venting options since July 1987. A draft revision to EP 5.3.7 prepared at that time was evaluated by the licensee's engineering personnel (memorandum from G. McClure to E. Mace, "Post Accident Venting of Primary Containment Evaluation", dated May 4, 1988). This revision of the procedure, which had not been issued at the time of this inspection, provided for venting through both small-bore (1-to 2-inch) and large-bore (20- to 24-inch) valves and piping from both the drywell and suppression pool, provided prioritization logic for use of the paths, and addressed the radiation release and dose assessment considerations. The operations support staff supervisor stated that the draft procedure had not been issued pending additional information from the owners' group on decay heat removal and NRC approval of the OG EPGs, Revision 4. The licensee was also conducting a study of potential overpressurization and failure of the vent path and the qualification of the containment hydrogen control nitrogen supply piping.

The team had the following observations and concerns regarding the licensee's program provisions for containment venting:

(1) The issued version of EP 5.7.3 did not include a number of the specific provisions included in the draft as indicated above. The team considered the issued version to be deficient in areas such as prioritized, multiple vent paths, and release and dose assessment linkage with the emergency plan implementing procedures. The licensee should consider issuing a revised procedure based on the draft that omits the use of equipment and flow paths deemed inappropriate by the engineering evaluation. The team acknowledged the licensee's need to resolve issues involving the use of the large-bore vent paths before issuing procedures for their use as discussed further below.

(2) The engineering evaluation above noted that the valves used for venting had been evaluated in conjunction with the manufacturers' specifications and found acceptable for operation at the differential pressures expected at containment design pressure. Teleconference memoranda documenting these discussions for the small-bore valves (MOV-305, -306, -1308, and -1310) addressed only the valves and not the capability of the actuators. The team requested that the licensee substantiate that the actuators and the actual actuator torque switch settings were capable of operating the valves as required. The licensee told a team member on July 14, 1988, that it had been confirmed that the valves were capable of withstanding up to 150 psid, although documentation was not yet available at the site. At the close of the inspection, the licensee was researching the above.

(3) The engineering evaluation included analysis of the standby gas treatment (SBGT) system design pressure versus expected venting pressures. The evaluation found that the SBGT duct work, fabricated of 14 gauge welded stainless steel, would not sustain the full containment design pressure of 65 psig but could be expected to rupture at approximately 63 psig. Additionally, the evaluation found that the SBGT filter housings were designed for a "leaktight" pressure of 2 psig; no design maximum pressure was specified. Considering the above conditions, the SBGT could not sustain the pressures encountered when venting through the large-bore valves, but the evaluation found that venting through the small-bore valves and piping would not threaten the duct and filters because of the low flow rates calculated.

However, neither the issued nor the draft procedures nor the engineering evaluation considered the case of inadvertent downstream isolation of the SBGT system when aligned to vent the containment, resulting in an equalization of containment pressure with the SBGT system. Such downstream isolation could occur if SBGT fan stoppage resulted in the closing of interlocked outlet valves. A simple precaution for the operator in the venting procedure appeared to be warranted.

The licensee acknowledged the above concern and its evaluation was in progress at the close of the inspection.

(4) EOP-2 initially limited venting temperature to 212°F (Step PC/P-2.b) on the basis of containment cooling considerations. However, if containment pressure exceeded the primary containment pressure limit, Figure 2-6, Step PC/P-8 instructed the operator to vent the containment irrespective of containment temperature.

The team's walkdown of the SBGT system found that some components (e.g., duct expansion joints) were made of plastic materials that may not have tolerated high temperatures and could warrant additional compensatory actions if high-temperature venting was necessary.

The licensee acknowledged the above concern and was evaluating it at the close of this inspection.

(5) Neither the issued nor the draft procedures addressed contingencies pertaining to venting such as loss of offsite power (diesel generators available) or station blackout (loss of all ac power) with respect to the need for access to the reactor building for local operation of the vent valves. Additionally, as discussed in Section 3.5 of this report, the licensee had not made any plans in regard to the need for access to perform such local operations with respect to accident radiation levels in the reactor building.

In response to the team's inquiry on this matter, the licensee stated that all valves in the flow path were dc battery powered and would be available during either scenario until the batteries failed except for valve MOV-306, the small-bore drywell vent isolation. The licensee also indicated that this matter would be given further consideration for future revisions of the procedures.

3.3 EOP Walkdown Findings

To ensure that the EOPs could be successfully carried out, the team performed walkdown evaluations of all the EOPs and supplemental procedures referenced in the EOPs. The team verified that EOP instrument and control designations were consistent with the installed equipment and that indicators, annunciators, and controls referenced in the EOPs were available to the operators. It also verified the location and control of EOPs in the control room. The team physically verified that activities which could be required outside the control room during an accident could be physically performed and that tools, jumpers, and test equipment were available to the operators. It also reviewed post-accident radiation and environmental considerations made by the licensee in regard to local operations in the reactor building.

During the plant walkdowns, the team identified the following discrepancies:

(1) EOP-3, Section SC/T, "Secondary Containment Temperature Control," Table 3-1 specified the entry conditions and action levels for elevated temperatures in about 30 rooms and areas of the secondary containment. The table included the maximum normal operating temperature, maximum safe operating temperature, and a temperature monitor alarm setpoint (corresponding to the maximum normal operating temperature) for each area.

During the walkdown on July 6, 1988, the team observed that the actual (as-found) setpoints for the temperature monitor alarms on control room panel 9-21 were about 10-15°F lower than those specified in EOP-3 and did not correspond to the entry and action-level temperatures; for example, the as-found setpoints for eight residual heat removal loop A and B area temperature channels ranged between 145°F and 148°F instead of being at 160°F as required.

The licensee stated that the above condition had been identified by its staff and was a result of instrument drift. The instruments were not periodically calibrated but were recalibrated only for corrective maintenance. The most recent calibration had been performed during August 1987. The licensee had determined that part of the drift problem was attributable to a new digital indicator installed in June 1988 and stated that it was trying to solve the problem. The licensee also stated that the frequency of monitoring this instrument drift was going to be increased until the drift problem was finally solved. The licensee had recalibrated the instruments successfully on July 7, 1988, and was preparing a new calibration procedure that would accommodate the instruments' drift characteristics. The licensee was going to perform this calibration procedure at a frequency that was also based on the instruments' drift characteristics.

The licensee stated that two sets of instruments (four steam tunnel temperature monitors and eight residual heat removal (RHR) area monitors) had not had their setpoints controlled as part of the engineering configuration management setpoint log program. These setpoints were being incorporated into the program at the close of this inspection. The licensee also stated that a review of all instruments and controls used for implementing the EOPs and referenced procedures was in progress to ensure that no other similar instances existed.

(2) Operating Procedure OP 2.2.69 3, "RHR Suppression Pool Cooling and Containment Spray," Revision 1, was invoked by various sections of EOP-2, "Primary Containment Control." The following two discrepancies were noted in this procedure:

(a) Section VII.A, Step 1.c note, cautions that RHR pump capabilities may be exceeded when the suppression pool cooling throttle valve was opened and specified a minimum pump differential pressure and a maximum pump motor current.

These parameters were not displayed in the control room. Differential pressure was indicated only on pump suction and discharge gages at the pump. Motor current was indicated only at the motor control center.

The licensee stated that the operators were trained to monitor available control room flow indications for stable pump performance and to dispatch operators to the above local indication locations should any aberrant conditions be observed. Licensed personnel generally confirmed the above but also indicated that their perceptions of stable flow and conditions that would require local monitoring were not consistent. Further, the locations where local pump pressure indications could be obtained would probably be inaccessible during accident scenarios involving core damage because of the levels of radiation from the RHR pump and piping. Postaccident plant access is discussed in Section 3.5 of this report. The licensee stated that the procedure intent would be evaluated by the task analysis of EOP referenced procedures being performed as part of the detailed control room design review.

b. Section VII.A, Steps h.2.c.1 through 3, provided instructions for overriding the containment cooling 2/3 core coverage valve control permissive. The valve, switch, and indication nomenclature used in the instructions was not consistent with that on the main control board switches and indications. For example, Step 1 required that the permissive keylock switch be placed in the "manual override" position. The switch was never removed from that position until Step 3 required that the switch be again placed in the "manual" position. Furthermore, the names in the procedure did not match those on the main control board. The senior reactor operator accompanying the team on the walkthrough was unable to interpret the procedure with respect to the actual controls to permit adequate performance of the step.

The licensee stated that the procedure and main control board labels had been reviewed, confirmed to be discrepant, and would be corrected.

(3) Reactor pressure vessel level indicator LI-92 (steam nozzle range level) (used in EOP-2, Table 2-1) was equipped with a dual-indicator scale. One scale was based on the "instrument zero" scaling that had been traditionally used at CNS. The second scale was based on top-of-active-fuel (TAF) scaling to which the licensee was changing as a human factors improvement. Both scales were displayed as an interim measure by the

licensee until the personnel became accustomed to the TAF scale, at which time the instrument zero scale would be removed.

The instrument was intended to measure level in the range at which the main steamline nozzles would flood and was equipped with a placard intended to correlate the two scales with the scale elevation of the steamline nozzles. However, the placard was so cryptic that only one of six licensed operators polled was able to interpret the information.

The licensee stated that its review confirmed the above discrepancy and the placard was changed.

(4) EOP-3, Attachment 1, provided instructions for installing jumpers in relay panels 9-41 and 9-42 to bypass the high drywell pressure and low reactor vessel level group 6 isolation signal to permit operation of the reactor building heating, ventilation, and air conditioning system. The licensee's prestaging of these and other jumpers and the placing of required authorization documents in a specially designated box in the control room were considered to be good practice. The licensee had twice successfully demonstrated the actual installation of the jumpers and had performed a functional test of the installed jumpers in accordance with Special Test Procedure No. 85-22, "RB HVAC Interlock and Containment Level Recorder Testing," in 1985.

The physical location of the jumper installations however, presented hazards from both equipment damage and personnel shock. The jumpers had to be installed using a screw driver and spaded wire lugs in a narrow terminal strip area about head high and two feet inside a vertical relay cabinet. Installation under stress conditions would be difficult. The licensee had recognized this and had initiated Design Change Request No. 88-196 on June 14, 1988, to install front panel jacks that would permit bypassing of the isolation signal without the need to enter the cabinet. On June 29, 1988, the plant staff had requested that this modification be given immediate priority for installation at the next outage of sufficient duration.

(5) Step RC/Q-9 of EOP-1 required that injection of boron into the reactor vessel via the reactor water cleanup (RWCU) system be discontinued when 275 pounds of boric acid and 275 pounds of borax had been added. A simulated walkdown of the procedure determined that no procedure or method was provided for determining the weights of the substances added. The licensee had identified this concern during the verification and validation program in 1984 and had dealt with it by stating that a procedure would be developed to determine the weights.

The licensee advised the team that the reference to weight in the procedure would likely be deleted because the current practice was to use a temporary transfer hose from the standby liquid control (SLC) tank to RWCU system, precluding the need to mix boric acid solution in the RWCU system, and the level in the SLC tank would be used as a basis for boron addition.

(6) Emergency Procedure EP 5.2.14, "Alternate Means To Inject Boron to RPV," Revision 2, which had been developed to support the EOPs, required filling the RWCU precoat tank from the SLC tank and then filling the RWCU

demineralizer from the preco t tank. The level to which the precoat tank was to be filled was not specified, and the point at which the precoat pump was started was vague. In addition, the procedure required pumping down the precoat tank to the "low level mark;" however, two station operators could not find the low level mark.

The procedure further required that certain switches be operated to prepare the RWCU system for boron injection. The nomenclature in the procedure was sufficiently different from the actual switch positions so that the operators were confused about the correct operation of the switches. For example, the procedure called for operating RWCU-AO-17A, yet the valve is labeled 12-4-17A. The licensee stated that it has committed to perform a task analysis for these EOP-related procedures as part of the resolution of a human engineering discrepancy identified under the detailed control room design review program.

(7) In the CNS emergency procedure guidelines (EPGs) the following sequence for opening the safety relief valves was given: G, A, E, H, C, F, B, AND D; however, on the main control board the following sequence was specified: D, G, A, E, H, C, F, AND B. The justification for this deviation from the CNS EPGs was not documented. The licensee stated that the step deviation documentation would be corrected.

(8) EOP-1, Step RC/L-7, referenced Operating Procedure (OP) 2.2.74, Section VII.I, for lining up alternate injection subsystems. The correct reference was OP 2.2.74, Section VII.H. The licensee advised the team that the correct reference will be incorporated.

(9) Step RC/P-15 of EOP-1 required the operator to verify that suppression pool water level was at or above five feet six inches on panel 9-3 or 9-4. The level instruments on these panels read only in feet and not in inches. The licensee advised the team that the procedure would be corrected to read 5 1/2-feet.

(10) Step RC/Q-10.b(3) of EOP-1 required venting of the scram air header by the removal of a pipe cap and the operation of instrument air (IA) valve IA-1601. This valve was not shown on the control rod drive (CRD) system piping and instrument diagrams, although the piping section in which the valve was located was shown. The valve also was not included on either the CRD or IA valve lineup checklists. The licensee stated that the valve was part of an open design change package and that the drawings and valve lists will be revised to reflect its installation.

(11) Step RC/P-19 of EOP-1 stated, "If defeating isolation interlocks is required, refer to GE Drawing 7916266, Primary Containment Isolation System (and applicable system drawings if necessary)." The referenced GE drawing contained 13 pages of electrical schematic and logic drawings. The absence of specific jumper and lifted lead instructions and prestaged materials appeared inappropriate. The team questioned the availability of staff, time, and materials during an emergency to research, evaluate, and implement interlock defeats. The licensee was reviewing the need for dedicated, preplanned jumpers and will attempt to simplify the procedure accordingly.

(12) Emergency lighting in the control room appeared insufficient to support EOP implementation during a loss of normal control room lighting. Specifically, lighting fixtures available for the control room supervisor's (CRS) desk and other areas where procedures were used appeared to be inadequate.

The licensee advised the team that additional emergency lighting was planned for installation during the next (1989) annual outage and that dedicated battery-powered lanterns had been placed in the control room emergency lockers on July 12, 1988.

3.3.1 Special Equipment and Tools

At various points the EOPs required special equipment (e.g., tools, hoses) for the successfull completion of a task. The team reviewed the prestaging of these items with regard to their availability during walkdowns and their availability for use during accident conditions. The team found that most of the equipment needed in the control room was prestaged with the appropriate paper work to support its use. In addition, the team found that the control room special equipment was stored in a specially marked box identified for EOP use.

The equipment needed for plant evolutions did not receive the same control. Typically, the equipment was not identified as "EOP equipment," was not segregated from equipment used for normal plant operation and was not controlled or inventoried to ensure availability when needed. The licensee had no procedures or practices in this regard. Specific examples included the following:

(1) Suppression pool temperature control in EOP-2 required operator action in accordance with Abnormal Procedure (AP) 2.4.2.3.1, "Relief Valve Stuck Open," if safety relief valves (SRVs) were stuck open. AP 2.4.2.3.1, Section IV.F, required that the SRV nitrogen supply regulator setting be verified or adjusted, if other attempts to close the valves had failed. The regulator was located on an elevated catwalk in a contaminated area above the control rod drive (CRD) hydraulic control units (HCUs) and required a wrench for adjustment. No tool was staged in the immediate vicinity or specifically identified for this operation. Several licensed personnel could not state with certainty (without entering the area) whether a wrench was needed to operate the regulator.

(2) EOP-1, Step RC/Q-20a, required the operator to connect a vent rig to valve CRD-157 for each rod. Special vent rigs and wrenches needed to perform this evolution were located adjacent to the north HCUs only. None were located at the south HCUs. In addition, the tools located near the north HCUs were also used for periodic venting of the units following refueling outages and were not specifically staged or identified for EOP use.

The team expressed concern about the availability of these tools during an emergency. In addition, the lack of tools at the south HCUs could result in unnecessary delays because of the requirements to dress and undress in anticontamination clothing to transfer the tools from the north HCUs, since the HCUs were located in different radiologically controlled areas.

Additionally, the normal operating ambient temperature in the HCU overhead area was more than 100°F. The licensee had not considered the temperature effects on personnel resulting from loss of ventilation in the area during an accident. Nor had the temperature rise in this area caused by venting the CRD water-steam mixture been considered in regard to such needs as temporary emergency ventilation and high-temperature gloves. Further, emergency lighting was not available in the area to permit performance during a loss of normal lighting.

(3) EOP-1 required the connection of a hose from the standby liquid control tank to the reactor water cleanup precoat tank. The hoses and tools were staged but were not identified for EOP use only. In addition, they were stored with other equipment used during routine plant operation.

(4) EOP-1, Step RC/Q-10.b, required the removal of a pipe cap to depressurize the scram air header in an attempt to insert control rods. A wrench was needed to remove the pipe cap. A wrench was located in the immediate vicinity; however, the wrench was not specifically designated for EOP use so its availability for emergency use was not ensured.

The licensee advised the team that a program for the dedication and control of EOP material and equipment would be developed to address the above concerns and that the specific deficiencies identified would be corrected.

3.4 Validation and Verification Program

The team reviewed the validation and verification program established by the licensee to support the implementation of and revisions to the EOPs. This program was modeled after Institute of Nuclear Power Operations 83-0045, "Emergency Operating Procedures Validation Guidelines." In its review of this program, the team found that CNS met the intent and requirements of this guide. The program included a review of associated documentation and personnel qualifications. Because the licensee did not have a simulator, the program included verification of the plant-specific procedures at the Dresden simulator.

The team reviewed the discrepancy sheets from the program to ensure that the identified discrepancies were properly dispositioned. Although the disposition process appeared generally satisfactory, the disposition of the following discrepancies appeared to be improper or inadequate:

(1) Discrepancy 84 recommended that jumpers be prestaged. The licensee's response to the discrepancy stated that all jumpers would be prestaged. However, the team found that jumpers required by EOP-1, Step RC/P-19 (discussed in Section 3.3(11) above), had not been prestaged, nor had the specific installation locations been identified. The licensee was reviewing the need for prestaging EOP-related material at the conclusion of this inspection.

(2) Discrepancy 3 stated that a method was needed to determine the weight of boron to be added via the alternate injection method (previously discussed in Section 3.3(5) above). The discrepancy disposition stated that a procedure would be developed to provide a method. As discussed in Section 3.3(5) of this report, no procedure was ever developed.

In general, the validation and verification program implemented at CNS appeared to be acceptable.

3.5 Postaccident Reactor Building Habitability and Reentry Considerations

The CNS EOPs required entry into the reactor building during and after an accident to perform local operations. In some cases, these local operations were backup actions due to other failures, (e.g., alternate boron injection on standby liquid control system failure and emergency control rod insertion on scram failures). In other cases, the actions were first-order emergency actions required for basic accident mitigation (e.g., closure of failed-open safety relief valves or condensate storage tank makeup to the suppression pool via the core spray system).

The team reviewed Emergency Plan Implementing Procedure 5.7.15, "Rescue and Reentry," Revision 6, which provided the instructions for personnel reentry into the reactor building, and determined that it included only very basic information on maximum dose limits and precautions for reentry. The procedure did not include specific reentry routes for expected EOP operations nor any information on anticipated dose rates.

NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.B.2, "Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post Accident Operations," required each licensee to provide for adequate access to plant areas to permit an operator to aid in the mitigation of or recovery from an accident. This item required the licensee to identify the plant areas requiring such access and to analyze the adequacy of radiation protection based on specific source terms. The licensee's evaluation and status were provided to the NRC in letters dated November 20, 1979, January 11, 1980, December 30, 1980, and April 16, 1982. NRC response and acceptance of the licensee's position was documented in an NRC safety evaluation report dated March 11, 1983, which was based, in part, on NRC Region IV Inspection No. 50-298/82-32 of November-December 1982. Using the NRC-specified source terms, the licensee had concluded that the postaccident radiation levels within the reactor building would preclude personnel reentry and stipulated that the plant design would support all accident operations without requiring reentry. These analyses and conclusions predated the availability of the current EOPs and apparently did not consider the EOP reentry requirements.

Discussions with the licensee's plant licensing and support staff personnel indicated that the reactor building radiation environment was informally considered during the preparation of the EOPs; however, correlation with NUREG-0737, Item II.B.2 data had not been made. The licensee stated to the team that the reentry requirement, reactor building radiation levels, and operator protective actions would be reevaluated.

3.6 EOP Simulation Using Classroom Walkthroughs

To ensure that the EOPs could be correctly implemented during emergency conditions, four accident scenarios were developed and conducted in which three licensed senior reactor operators (SROs) and one shift technical advisor participated. Each SRO was given the opportunity to function as the control room supervisor and to direct simulated plant operations using the EOPs. The scenarios were conducted to: (1) determine if the EOPs provided the operators with sufficient guidance so that their required actions during an emergency were clearly outlined, (2) verify that operator actions were not duplicated in the procedures unless required, (3) verify that the transition between EOPs and other supplemental procedures could be accomplished satisfactorily, and (4) verify that procedures in different EOP sections could be executed concurrently.

Because CNS did not have a site-specific simulator and the plant was operating at full power, it was necessary to conduct table-top scenarios in the classroom to evaluate the EOPs.

Realistic scenarios with an accurate time line were developed by the NRC operator examiner team member. The operators were given the initial plant conditions, major equipment out of service, and the initiating event. The control room supervisor directed the reactor operator and balance-of-plant operator to perform the actions as required by the EOPs. The NRC operator examiner functioned as the controller. The controller provided plant status, equipment status, and plant parameters to the operators. The plant parameters were periodically updated on a calculated time base as the accident scenario progressed. The licensed SROs were directed to simulate actions and responses based on this input from the controller. Two team members monitored the control room supervisor's ability to direct plant operations in accordance with the EOPs.

3.6.1 Scenario Descriptions

The first scenario was designed to be a simple introduction to familiarize the licensed operators and the NRC team with the expected response of the plant operators and the controller. This scenario involved a total loss of feedwater with the resultant reactor scram occurring on low reactor pressure vessel (RPV) water level. All safety systems were allowed to function as designed to restore level. EOP-1 was entered on low RPV water level, which required the control room supervisor to execute the sections entitled "RPV Water Level Control (RC/L)," "RPV Pressure Control (RC/P)," and "RPV Power Control (RC/Q)," concurrently. The heat addition to the suppression pool from the high pressure coolant injection system and the reactor core isolation cooling system exhaust steam required entry into EOP-2 when the suppression pool temperature exceeded 95°F. EOP-2 required the control room supervisor to execute sections entitled "Suppression Pool Temperature Control (SP/T)," "Drywell Temperature Control (DW/T)," "Primary Containment Pressure Control (PC/P)," and "Suppression Pool Level (SP/L)," concurrently. The scenario was terminated when RPV level was restored to the range of +15 to +55 inches and suppression pool cooling had reduced the suppression pool temperature to less than 95°F.

The second scenario included a failure of the traversing incore probe (TIP) drive mechanism withdraw limit switch which allowed the TIP probe to be withdrawn into the drive mechanism. Area radiation levels exceeding the maximum safe operating value required entry into EOP-3. EOP-3 required the control room supervisor to execute the sections entitled "Secondary Containment Temperature Control (SC/T)," "Secondary Containment Radiation Control (SC/R)," and "Secondary Containment Level Control (SC/L)," concurrently. The scenario was terminated when the required actions of EOP-3 and temporary shielding installation had been simulated.

The third scenario involved a loss of all high pressure injection systems. The initial conditions given the operators included high pressure coolant injection system and B control rod drive pumps out of service, 100-percent rated power, and end of core life with all rods out. The initiating event was a rupture of the common suction line between the condenser hotwell and the condensate pumps. This failure resulted in a total loss of condensate and feedwater pumps resulting in a reactor scram on RPV low level and a Group I isolation on low condenser vacuum. The reactor core isolation cooling (RCIC) system received an initiation signal but was immediately tripped and isolated because of a steam leak in the RCIC room. The control room supervisor entered EOP-1 on low RPV level and high RPV pressure. EOP-2 was entered on high suppression pool temperature. EOP-3 was entered on a high RCIC area temperature. RPV pressure was controlled by the use of safety relief valves with low-low set logic in control. With only one control rod drive pump available, RPV level decreased to top of active fuel (TAF). When RPV level reached TAF, the control room supervisor ordered RPV emergency depressurization, which allowed the low pressure coolant injection and core spray systems to inject and restore level. EOP-2 was exited when the suppression pool temperature was reduced to less than 95°F. EOP-3 was exited when the RCIC system steam leak was isolated and the RCIC area temperature decreased below its maximum normal operating value.

The fourth scenario involved a pipe rupture in the turbine digital electro-hydraulic (DEH) control system with a failure to scram. The DEH failure resulted in a turbine trip and bypass valve failure; the RCIC system functioned normally on low RPV level. The control room supervisor was required to execute concurrently RC/L, RC/Q, RC/P, and level power control from EOP-1. EOP-2 was entered on high suppression pool temperature. RPV level was lowered to TAF in accordance with level power control. The residual heat removal system automatically realigned from suppression pool cooling to low pressure coolant injection at -145.5 inches, at which time both suppression pool cooling discharge valves failed closed. The suppression pool temperature exceeded the heat capacity temperature limit of EOP Figure 2-1, which required emergency RPV depressurization. This scenario was terminated when the hot-shutdown weight of boron was injected and RPV level was maintained between +15 and +55 inches.

3.5.2 Scenario Observations

Placekeeping (finding and keeping the correct place in the EOPs) was a major problem for the operators while performing the table-top scenarios. The team also determined from discussions with the operators that placekeeping was a problem when performing the EOPs on the simulator.

It appeared to the team that the EOPs were cumbersome to use because of the numerous concurrent actions that must be performed and the large volume of text that had to be read. During the execution of the classroom scenarios, the control room supervisor frequently lost his place while attempting to execute the required EOP and contingency actions. The supervisor and other operators appeared to know what action had to be taken, but the supervisor had a problem locating the correct steps in the EOPs.

Mechanisms implemented by the licensee to aid in placekeeping included: dividing the EOPs into separate binders with EOP-1 in one binder, EOP-2 in a second binder, and EOP-3 and EOP-4 in a third binder; attaching colored ribbons to each binder for marking pages; and placing a blank line at each action to check off completion of the action.

However, in practice it did not appear that the ribbons were effectively used or that the blank lines were checked off to assist in tracking. A contributing factor to the placekeeping problem appeared to be the lack of training given the operators in this area.

Another problem observed during execution of the classroom scenarios was that the control room supervisor did not have time to read the cautions, notes and special operator instructions (SOIs) that were an essential part of the EOPs. In general, these items were well marked and were inserted in line with the logic flow. However, when the EOP logic directed a jump to a specific step, the tendency was to ignore any cautions, notes, or SOIs preceding the step and proceed directly to the instructions following the step label.

The team felt that the dual-column format as implemented in the CNS EOPs could be contributing to the placekeeping problem. The usual dual-column format has the conditions (IFs) in the left column and the actions (THENs) in the right column. In the implementation at CNS, the left column (of right-hand pages) contained primary actions (both conditions and actions), and the right column contained contingency actions (both conditions and actions), which were alternatives if the conditions of the primary action were not met. This was intended to save reading the right column if the primary action worked. The writers' guide also allowed supplementary information to be put in the right column, if it was brief; otherwise it was to be placed on the left (facing) page.

During the review, the team noted the following deviations from the above concept:

(1) Some of the action steps in the right column were not "contingency" but rather "how to do it" actions for the primary action (e.g., Step RC-3).

(2) Sometimes it was not clear whether a paragraph in the right column was part of an action step or just supplemental information, (e.g., Step RC/L-3, right column, last paragraph).

(3) The operators appeared to save no time, since both columns had to be read to see what was in them.

(4) In some cases the contingency actions appeared to be more like a primary action, (e.g., Steps RC-4, RC/L-2).

(5) In some cases there did not seem to be a logic path to a right-column step, (e.g., Step RC/L-8, which perhaps should be a special operating instruction).

(6) In numerous cases action steps did not have the checkoff line and some supplemental information items did.

The team had a concern that the cumbersome EOPs could encourage operators to take action in response to plant parameters, based on memory, rather than following a step-by-step progression through the EOPs. If this happened, the operators could be making assumptions and taking action without benefit of the accident mitigation strategy and supplemental information (e.g., cautions, notes, and special operating instructions) contained in the EOPs which were developed on the basis of operation of the entire plant and its interrelated systems.

Overall, the operators felt and appeared confident that they could navigate through the logic, and this format was acceptable to them.

3.7 EOP Training

3.7.1 Initial Training

The team reviewed the initial training conducted to implement the CNS EOPs. This training consisted of five days of classroom training, three days of simulator training on the CNS EOPs at the Dresden simulator, and a 4-hour in-plant walkthrough conducted by the CNS training staff.

3.7.2 Requalification Training

EOP-related requalification training was conducted during each annual training period. Classroom discussions of the EOPs were conducted with the primary emphasis being on explanation and understanding of the steps and cautions contained in the EOPs. To improve operator performance with the EOPs, the licensee had recently implemented training with classroom scenarios using an instructor as a controller. Training was also provided on all revisions to the EOPs. The CNS shift technical advisors were included in the EOP training sessions.

In-plant training walkthroughs that emphasized familiarization with the equipment and operations required outside the control room were conducted on a biannual basis. Nonlicensed station operators were included in the portion of the walkthroughs conducted outside the control room.

CNS operators attended five days of annual requalification training at the Dresden simulator. This training consisted of classroom discussions and simulator scenarios that emphasized EOP-1 and EOP-2. The Dresden simulator modeling would not support the performance of EOP-1, Attachment 3, "Alternate Shutdown Cooling." However, all other contingency procedures of EOP-1 and EOP-2 were performed. Simulator modeling would not support training on EOP-3 and EOP-4. Classroom scenarios were used to train the operators on the use of EOP-3 and EOP-4, and these two EOPs were normally performed during the annual emergency plan drill.

3.7.3 Observations

The team concluded that the CNS EOP initial and requalification training for the licensed operators and shift technical advisors (STAs) was adequate, with the exception of the demonstrated weaknesses in placekeeping methods discussed above.

Implementation of EOP table-top classroom scenarios that required the operators to perform more than one EOP concurrently could improve the operators' place-keeping abilities. The licensee stated that possible alternatives to the existing placekeeping method using ribbons attached to each binder would be reviewed and more emphasis would be given to placekeeping in future EOP training sessions.

The team expressed concern regarding the nonlicensed station operator training. The licensee stated that the station operators were included in the biennial plant walkthrough portion of the licensed operator and STA training. No additional walkthroughs were conducted for those station operators who were qualified during the period between the biennial licensed operator walkthroughs. This concern was discussed with the operations training supervisor who, in response to the team's inquiries, initiated a training work request to include EOP training for in-plant evolutions and equipment in the station operator certification program.

3.8 Human Factors Review

To evaluate the adequacy of the EOPs with respect to human factors principles, the EOPs were compared with NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," and the CNS EOP Writer's Guide, Revision 3. Frequent reference was also made to the CNS EOP Training Manual (INT008-04-01 through 04-13), the CNS EPGs, Revision 2, and the step documentation (deviation rationale) relating the CNS EPGs to the EOPs in order to determine the rationale for the implementation of the EOPs. Human factors issues were also evaluated and discussed during the control room and plant walkdowns, the simulated (classroom) event simulations, and interviews with CNS personnel.

3.8.1 Hardware/Procedure Interface

The control room panels had been recently redesigned and, with minor exceptions, were well organized, well marked, and accessible. References to the displays and controls in the EOPs were generally very good. The CNS unique safety parameter display system appeared to be effectively used and was appropriately referenced in the EOPs. Communication within the control room and with the plant station operators appeared to be good, although a formal repeat-back method of oral communication was generally not used. Radios were available and were sometimes used. Normal lighting in the control room was good, but emergency lighting in case of station blackout appeared to be inadequate; steps were being taken to improve the emergency lighting levels. Space for laying out the EOP books during implementation was adequate; multiple copies of referenced procedures were available and had been assembled into a single volume. In-plant equipment was well labeled (with minor exceptions), and the spaces were clean and accessible.

3.8.2 Adherence to the Writer's Guide and NUREG-0899

The writer's guide incorporated the requirements of NUREG-0899 and additionally specified format and organizational requirements for the EOPs. General adherence to the writer's guide was found to be very good, especially in regards to page layout and general organization. The team discussed a number of specific deviations in detail with the CNS staff and found that none of the deviations rendered the EOPs unusable.

3.8.3 Implementation of EOP Contingency Procedures

The owner's group emergency procedure guidelines (OG EPGs), Revision 3I, and the CNS EPGs, Revision 2, both identified seven contingency procedures. The first four of these procedures were implemented in the CNS EOPs by inserting them into the normal logic flow of EOP-1, not necessarily defined by name. The other three were placed in separate sections as attachments to EOP-1.

The justification for inserting the first four contingency procedures into the logic flow but leaving the last three as separate attachments was unclear. The step documentation stated that this had been done, but did not explain why. The training manual explained that the attachments were kept separate so they could be referenced in all the EOPs, yet the attachments were not the contingency procedures that were referenced the most. The procedure pertaining to emergency depressurization was referenced 18 times, in all EOP sections, yet was inserted. The procedure pertaining to level power control was referenced twice, in EOP-1 only, but was separate. The training manual also stated that the inserted versions were reproduced fully wherever they were required in the procedures. This was not done; all 18 references to emergency depressurization referred to a single location (procedure tab 6). There did not appear to be any benefit to inserting the contingency procedures, especially since the operators seemed to regard them (and identify them by name) as separate groupings of procedural actions even when they were inserted.

The inconsistent treatment of the contingency procedures did not appear to help the operators and could contribute to the complexity of the logic flow. Insertion blurred the distinction between the normal conditions requiring the use of the EOPs and the more degraded conditions requiring the use of the contingency procedures, and created a disconnect between the need to identify these situations in training and the effort to hide the distinction by insertion of the procedures.

3.8.4 Supplemental Information

A great deal of supplemental information was incorporated in the EOPs to support the action steps. The team found that the level of detail was appropriate and that the repetition of information wherever needed reduced referencing and the turning of pages. Further supplemental information appeared warranted as follows:

(1)	Page 28A, 1.a	Use values rather than "high," "medium, and "low."
(2)	RC/L-12.d	Suggest list of possibilities.
(3)	RC/Q-9a	Identify Key No. 54-55.
(4)	RC/Q-12	Specify expected indication.
(5)	RC/P-19	Supply references for main condenser and head vent.
(6)	EOP-1, Page A3-10	Cooldown rate - include method of observation.
(7)	EOP-1, Page A2-9b	Supply procedure to restore automatic depressurization system to standby.

(8) RC/P-19 Reference to GE Drawing 791E266 is impractical; provide procedure.

(9) Calculations Provide extra sheets for repeat calculations.

3.9 Ongoing Evaluation of EOPs

Paragraph 6.2.3 of NUREG-0899 states that licensees should consider establishing a program for the ongoing evaluation of the EOPs. The licensee had not implemented a formal, proceduralized, ongoing EOP evaluation program. However, the team verified that ongoing evaluation had been performed by discussions with cognizant licensee personnel; review of Procedure 0.22, "Preparation, Review, and Approval of Emergency Operating Procedure Changes," Revision 2; and review of the development of the current CNS EOPs.

Procedure 0.22 required that the EOPs and the EOP plant data table be reviewed annually. This procedure also required that the EOPs be reviewed within 90 days after the NRC issues a safety evaluation of the Boiling Water Reactor Owners' Group emergency procedure guidelines (BWROG EPGs). The licensee stated that the EOPs would be updated in accordance with Revision 4 of the BWROG EPGs when they are approved by the NRC.

Since their implementation in 1985, the CNS EOPs have been revised three times (Revision 4 was in effect at the time of this inspection). The need for these revisions was primarily identified through feedback from operator requalification and EOP simulator training. Licensee personnel stated that they were considering adding an EOP feedback report form to Procedure 0.22 to make it easier for personnel to provide feedback on the EOPs.

4.0 POSTACCIDENT COMBUSTIBLE-GAS CONTROL

The CNS EOPs provided no postaccident combustible-gas control instructions in the event the containment hydrogen and oxygen concentration limits were exceeded. Unlike later BWR-4 plants, CNS did not have a nitrogen containment atmosphere dilution (NCAD) system. The licensing basis for CNS called for such a system to be installed during the first refueling outage. However, an air containment atmosphere dilution (ACAD) system was installed instead. Staff review and approval of the ACAD system was nearly complete at the time of the accident at Three Mile Island (TMI). At that time the review was terminated to concentrate on TMI-related work. The hydrogen/recombiner rule, 10 CFR 50.44, was subsequently issued, and the review of the ACAD system was never resumed. By letter dated July 1, 1986, the NRC staff advised the licensee that it should attempt to demonstrate that the containment nitrogen inerting system could be successfully used under postaccident conditions as a nitrogen dilution system. The licensee has prepared a draft response but was awaiting NRC staff guidance before submitting it. Oyster Creek, Millstone-1, Quad Cities 1 and 2, and Dresden also did not have NCAD systems and were similarly affected.

5.0 EXIT MEETING/PERSONS CONTACTED

On July 12, 1988, the team and other NRC representatives met with licensee personnel and discussed the scope and findings of the inspection. Persons contacted by the team and attendees at the exit meeting are identified in Attachment A. Mr. J. J. Jaudon, Deputy Director, Division of Reactor Safety, RIV, and Mr. L. J. Norrholm, Section Chief, Special Inspection Branch, NRR, represented NRC management at the exit meeting. During the inspection the team also contacted other members of the licensee's staff to discuss issues and ongoing activities.

ATTACHMENT A

PERSONS CONTACTED

EXIT MEETING ATTENDEES

NAME	ORGANIZATION	TITLE
*P.L. Ballenger	NPPD	Operation Engineering Supervisor
*L.E. Bray	NPPD	Regulation Compliance Specialist
D.W. Bremer	NPPD	Operations Support Group Supervisor
*R. Brungardt	NPPD	Operations Manager
D.M. Dea	NPPD	Senior Reactor Operator
M.C. Daus	NPPD	Consultant
*J.R. Flaherty	NPPD	Plant Engineering Supervisor
*R.A. Gardner	NPPD	Management Trainee - Operations
M.D. Hannaford	NPPD	Reactor Operator
D.P. Helms	NPPD	Station Operator
G.R. Horn	NPPD	Nuclear Operations Division Manager
D.T. Kuser	NPPD	Operations Support Group Engineer
H.A. Jantzen	NPPD	Instrumentation & Control Supervisor
B.A. Lipsemeyer	NPPD	Shift Supervisor
*J.M. Meacham	NPPD	Senior Manager, Technical Support
*D.A. Shalleberger	NPPD	Training Instructor
S.C. Smallfoot	NPPD	Shift Supervisor
*G.R. Smith	NPPD	Licensing Supervisor
*G.E. Smith	NPPD	Quality Assurance Manager
*M.L. Sparr	NPPD	Assistant to Operations Manager
R.J. Tanderup	NPPD	Control Room Supervisor

*Denotes those present at the exit meeting on July 12, 1988.

ATTACHMENT B

LICENSEE'S DOCUMENTS REVIEWED

NUMBER	TITLE	REVISION
EOP-1	Reactor Pressure Vessel Control	4
EOP-2	Primary Containment Control	4
EOP-3	Secondary Containment Control	4
EOP-4	Radioactive Release Control	4
EOP-C	Operator Precautions	4
EP 5.8	Emergency Operator Procedure Introduction	4
EP 5.2.14	Alternate Means To Inject Boron to RPV	2
EP 5.3.7	Post Accident Venting of Primary Containment	2
EP 5.8	Emergency Operating Procedures	4
OP 2.2.69.3	RHR Suppression Pool Cooling and Containment Spray	1
AP 2.4.2.3.1	Relief Valve Stuck Open	17
OP 2.2.73	Standby Gas Treatment System	17
OP 2.2.40	HVAC Drywell Cooling	9
SP 3.5	Reactor Building HVAC Interlock and Containment Level Recorder Testing	0
0.22	Preparation, Review, and Approval of Emergency Operating Procedure Changes	2
0.4.1	CNS Controlled Documents Other Than CNS Procedures and Vendor Manuals	0
0.36	Industrial Safe Work Permit	Draft
INT0800 -04-01 through -04-13	CNS Training Manual (EOPs)	0
--	BWR Owners' Group Emergency Procedure Guidelines, Including Appendices A, B, and C	3 & 3I
--	CNS Emergency Procedure Guidelines	2
--	CNS Step Deviation Documentation	NA
--	CNS Procedures Generation Package	2
	NPPD QA Program for Operation Policy Document	4

ATTACHMENT C

ABBREVIATIONS AND ACRONYMS

ACAD	air containment atmosphere dilution
AP	abnormal procedure
BWROG	Boiling Water Reactor Owners' Group
CNS	Cooper Nuclear Station
CRD	control rod drive
CRS	control room supervisor
DEH	digital electrohydraulic
EOP	Emergency Operating Procedure
EP	Emergency Procedure
EPGs	emergency procedure guidelines
GE	General Electric
HCU	hydraulic control unit
IA	instrument air
NCAD	nitrogen containment atmosphere dilution
NPPD	Nebraska Public Power District
NSSS	nuclear steam supply system
OG	owners' group
OP	operating procedure
PGP	procedure generation package
PSTG	plant-specific technical guidelines
PSWG	plant specific writers guide
RCIC	reactor core isolation cooling system
RHR	residual heat removal
RPV	reactor pressure vessel
RWCU	reactor water cleanup
SBGT	standby gas treatment
SLC	standby liquid control
SOI	special operating instruction
SRV	safety relief valve
TAF	top of active fuel
TI	temporary instruction
TIP	traversing incore probe
TMI	Three Mile Island

<u>EOP Control Section Designations</u>

RC/L	reactor pressure vessel/level
RC/P	reactor pressure vessel/pressure
RC/Q	reactor pressure vessel/power
DW/T	drywell/temperture
PC/P	primary containment/pressure
SP/T	suppression pool/temperature
SP/L	suppression pool/level
SC/L	secondary containment/level
SC/R	secondary containment/radiation
SC/T	secondary containment/temperature