UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

April 22, 2002

Duke Energy Corporation
ATTN: Mr. W. R. McCollum
Vice President
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION - NRC SPECIAL INSPECTION REPORT 50-269/02-08, 50-270/02-08, AND 50-287/02-08

Dear Mr. McCollum:

This refers to the special inspection conducted from March 19 to 22, 2002, at your Oconee 1, 2, and 3 reactor facilities. The inspection focused upon your staff's ability to safely operate the Standby Shutdown Facility (SSF) with the pressurizer in a water solid condition during events where the SSF is used to achieve safe shutdown. The enclosed report documents the inspection findings which were discussed on March 21, 2002, with you and members of your staff.

Based on the results of this inspection, no findings of significance were identified. The inspectors concluded there was reasonable assurance the SSF would perform its design basis function with the temporary compensatory measures implemented at your facilities.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's Document system (ADAMS). ADAMS is accessible from the NRC web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Charles A. Casto, Director
Division of Reactor Safety

Docket Nos.: 50-269, 50-270, 50-287
License Nos.: DPR-38, DPR-47, DPR-55

Enclosure: (See page 2)

Enclosure: NRC Inspection Report 50-269/02-08,
50-270/02-08, 50-287/02-08 w/Attachments

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U.S. NUCLEAR REGULATORY COMMISSION
REGION II

Docket Nos:	50-269, 50-270, 50-287
License Nos:	DPR-38, DPR-47, DPR-55
Report Nos:	50-269/02-08, 50-270/02-08, 50-287/02-08
Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7800 Rochester Highway Seneca, SC 29672
Dates:	March 19 - 22, 2002
Inspectors:	W. Lyon, Senior Reactor Engineer S. Freeman, Resident Inspector C. Payne, Team Leader
Approved by:	C. Ogle, Chief, Engineering Branch 1 Division of Reactor Safety

Enclosure

SUMMARY OF FINDINGS

IR 05000269-02-08, IR 05000270-02-08, IR 05000287-02-08, on 3/19 - 22/2002, Duke Energy Corporation, Oconee Nuclear Station, Units 1, 2, & 3, SSF special inspection.

On March 7, 2002, the licensee determined that the capacity of the pressurizer heaters which are supplied power from the standby shutdown facility (SSF) may be insufficient to compensate for heat losses from the pressurizer during events where the SSF is used to achieve safe shutdown. This report covers a four-day special inspection to determine whether the SSF would perform its design basis function with the temporary compensatory measures implemented by the licensee for this degraded/nonconforming condition.

<u>Inspector Identified Findings</u>

Cornerstone: Mitigating Systems

- No findings of significance were identified.

- The inspectors concluded there was reasonable assurance the SSF would perform its design basis function with the temporary compensatory measures implemented by the licensee.

Report Details

Introduction

In January and February 1999, the licensee identified a concern regarding the number of pressurizer heaters (kilowatts (kW) of heater capacity) required to support operation of the standby shutdown facility (SSF). Operator training specified five of nine heaters (70 kW) were required. However, the Updated Final Safety Analysis Report (UFSAR) discussed two values of heater capacity, 107 kW and 126 kW. These concerns were documented through the licensee's problem investigation process (PIP). Also during this period, the licensee revised the Core Operating Limits Report (COLR) pressure limit upward by 25 pounds per square inch gauge (psig) following a Duke Energy Corporation (DEC) General Office (GO) review of UFSAR Chapter 15, "Accident Analysis." However unknown to the GO safety analysts, due to problems discussed below, the average reactor coolant system (RCS) pressure had decreased about 20 psig. Rather than cycling around a set pressure of 2155 psig, actual pressure was cycling around 2135 psig. With the previous, lower COLR limit, this discrepancy had not been recognized as significant by the plant operators. After implementing the new, higher COLR limit, as RCS pressure drifted to the low end of the control band, it would occasionally dip below the COLR pressure limit before pressurizer backup heaters could respond and raise pressure. Additional PIP's were initiated over time to document deficiencies in pressurizer insulation and document the issues related to temporary decreases in RCS pressure below the Technical Specification minimum limits as defined in the COLR.

During its investigation in June 2000, the licensee identified that the pressurizer heater input required to compensate for ambient losses and pressurizer spray flow had slowly increased over years of operation. A small increase in ambient losses was attributed to insulation deficiencies. Likewise, a significant increase in spray flow heat losses was attributed to degradation of the spray valves through mechanisms such as erosion and seat leakage. The overall effect was an increase, over time, in the number of pressurizer heaters (kW) required to maintain equilibrium conditions in the pressurizer. Heater power demand had increased such that the normal controlling bank of heaters (modulating heater bank 1) could not on its own, maintain RCS pressure at its setpoint. Pressurizer heater bank 2 (normally operated in the off condition) had to cycle on and off to compensate. The licensee initiated corrective action plans to adjust the pressurizer heater setpoints, replace the leaking pressurizer spray valves, upgrade pressurizer insulation and replace any failed pressurizer heater bundles.

Also during this period, the licensee evaluated the need to perform a special test to determine the actual pressurizer ambient heat loss. Performance of such a test would require closure of the spray line block valve in order to eliminate any heat loss from spray flow due to the degraded condition of the spray valves. However, the licensee's engineering organization was concerned about the thermal effects on the spray line resulting from shutting the spray line block valve. Replacement of the pressurizer spray valves on all three units would eliminate the need to close the spray line block valve. Thus, consideration of an ambient heat loss test was postponed until all three unit's spray valves could be replaced.

In January 2001, the licensee's engineering organization met to review pressurizer heater control of the RCS. From this review, engineering proposed continuously operating one of the backup heater banks (equivalent to 50 percent of the heater bank 1 power capacity). This would allow the bank 1 heaters to modulate from about 50 percent power capacity thus permitting RCS pressure control at setpoint. The licensee also identified that the control setpoints for pressurizer heater banks 3 and 4 had not been adjusted from their original design setpoints despite the upward changes made to the COLR operating limits. Minor modifications were initiated to adjust these controlling setpoints upward. Additionally, the pressurizer spray valves were replaced with the last unit being completed in the summer of 2001.

Once the spray valves had been replaced, the licensee's engineering organization began preparing a test procedure, for use during the upcoming refueling outages, to determine the pressurizer ambient heat losses. During development of this test procedure, a licensee engineer recognized, based on changes made in pressurizer heater control and repair of the pressurizer spray valve, sufficient information was now available to calculate (rather than test) a close approximation of each unit's pressurizer ambient heat loss. Results of the calculation determined the calculated ambient heat losses were greater than the capacity of the pressurizer heaters powered from the SSF. On March 7, 2001, the licensee initiated PIP O-02-01066 to document this issue in the corrective action program.

Recognizing there was insufficient SSF pressurizer heater capacity to maintain a steam bubble during events where the SSF is used to achieve safe shutdown, the licensee developed a strategy for operating the pressurizer in a water solid condition. The licensee considered this modified operating strategy a temporary compensatory measure for a degraded or nonconforming condition. This strategy would be used in the SSF until long term corrective actions could restore the SSF design basis. The objective of this four-day, special inspection was to ascertain whether the SSF would perform its design basis function with the licensee's compensatory measures for the above problems. The charter for this inspection is provided as Attachment 2 to this report.

4. OTHER ACTIVITIES

OA3 Event Follow-up

.1 Thermo-Hydraulic Analyses

a. Inspection Scope

The inspectors assessed the thermal-hydraulic aspects of solid operation with respect to two objectives:

(1) Reasonably ensure continued subcooling in the highest elevation of the RCS hot legs to preclude formation of a steam bubble that could block natural circulation transport of decay heat from the core to the steam generators.

(2) Keep RCS pressure below the pressurizer safety relief valve lift pressure to avoid valve actuation.

The inspectors' assessment included evaluation of the licensee's RETRAN computer code modeling and predictions of the initial RCS heatup followed by solid operation for a loss of all feedwater event with a simultaneous loss of all alternating current (AC) power.

The inspectors assessed the potential for thermal-hydraulic behavior to introduce errors in temperature and pressure instrumentation.

b. Observations and Findings

i. Instrumentation and Control During Water Solid Operation

The principal instrumentation concerns were with the RCS pressure and temperature instruments. Of interest were each instrument's specific location within the RCS piping as well as the potential for non-uniform temperatures in the vicinity of the temperature instrumentation. Instrument location is important because of the need to know what is happening at a critical location – the highest elevation in the hot legs. Temperature non-uniformity is an important concern because it could lead to instruments failing to indicate the highest RCS temperature.

Pressure indication in the SSF is derived from a pressure instrument tap located about 7.5 feet below the centerline of the highest RCS hot leg pipe elevation. Thus, indicated pressure would expected to be about 3 psi higher than at the highest hot leg pipe elevation, a value small enough to be of no concern with respect to operation and maintenance of subcooling. Further, no significant pressure variation is expected across a horizontal plane within this region of the hot leg. The inspectors concluded the pressure indication location is adequate for operating the SSF with the pressurizer in a water solid condition.

Temperature indication is derived from a location about two feet below the pressure instrument tap. The temperature sensor is located in a thermal well that penetrates into the side of the RCS piping closest to the steam generator and measures temperature within a few inches of the inside of the pipe wall. As long as natural circulation is maintained, this elevation is adequate with respect to temperature measurement. Little temperature variation is expected between this location and the top of the hot leg provided there is no temperature variation in a plane perpendicular to the pipe axis. To substantiate uniformity of temperature at the measurement location, the licensee provided core exit thermocouple data from a 1974 Oconee Unit 1 natural circulation test that showed a core exit temperature variation from 551° Fahrenheit (F) to 555°F. Corresponding hot and cold leg temperatures were 555°F and about 530°F, respectively. These data were sufficient for the inspectors to conclude that natural circulation core exit temperature variation would be substantially less than during power operation.

Most of the water exiting the core in the Babcock & Wilcox (B&W) design flows upward in the upper plenum and, with respect to elevation, makes a 180° turn as it passes to and through openings in the cylindrical structure that surrounds the upper plenum. The water then flows downward, and makes another 90° turn to enter the hot legs. These turns will mix core exit water. There is further mixing due to azimuthal flow near the hot leg entrance and in the long hot legs before the water reaches the temperature sensor location. The inspectors concluded that the combination of the small core exit temperature variation measured under natural circulation conditions and the significant mixing between the core exit and the hot leg temperature sensors means there is little temperature variation within the hot legs in the vicinity of the temperature sensors. The inspectors concluded the temperature indication location is adequate for operating the SSF with the pressurizer in a water solid condition.

The licensee provided information demonstrating an appropriate allowance had been made for temperature and pressure instrument error in the SSF emergency procedure. Because the temperature and pressure instrumentation are located to correctly represent RCS physical properties during SSF operation and because instrument error is properly accounted for, the inspectors concluded there were no concerns with measurement of RCS temperature and pressure.

ii. Potential Interactions Between Units due to Changing Feedwater Flow Rates

The SSF auxiliary service water (ASW) pump can provide water to the steam generators for Units 1, 2, and 3. The analyses supporting this compensatory measure were performed for one unit, with the assumption that there would be no interaction between units. However, because operators can independently control ASW flow rate and steam generator pressure can change as safety valves open and close, the inspectors requested information demonstrating that changing characteristics in one unit's steam generators would not cause a significant perturbation to either of the other units. In response, the licensee provided the characteristic curve for the SSF ASW pump which shows the developed head to be 3184 feet (ft) at zero gallons per minute (gpm), 3208 ft at 400 gpm, 3184 ft at 800 gpm, and 3097 ft at 1200 gpm. The licensee verbally described use of this curve with a pipe flow model to determine flow resistance across the CCW-268 control valve(s) with an assumed 150 gpm into each unit's steam generators at 1060.5 psig. The licensee then ran a second calculation assuming the Unit 3 steam generators were at 945 psig with the Unit 1 and Unit 2 steam generators at the originally assumed 1060.5 psig. Flow rate into the Unit 1 and Unit 2 steam generators was predicted to be 149 gpm while the Unit 3 flow rate increased to 178 gpm. The licensee concluded perturbations affecting one unit would not perturb the other units.

The inspectors expected there would be little inter-unit dependence after examining the pump curve. Inspector review of the calculations confirmed that expectation. The inspectors estimated that the one gpm flow rate reduction would cause reactor coolant system pressure to increase at about two psig per minute which was within the bounds of the analysis. The inspectors agreed with the licensee's conclusion that perturbations in one unit's steam generators should not perturb behavior in the other units.

iii. RETRAN Modeling

The NRC staff has extensive experience with the RETRAN computer code. The code is widely used, and it is capable of predicting system response under water-solid conditions. Consequently, the inspectors limited their assessment to the licensee's application, the predictions, and evaluation of the results.

The licensee uses a proprietary RETRAN nodalization that is basically a single dimension model with a modest number of nodes in the reactor vessel and the hot and cold legs. The steam generators are finely nodalized in the vertical dimension. The absence of large temperature variations at the core exit, as exhibited in the 1974 natural circulation test discussed above, justifies the absence of circumferential modeling in the reactor vessel as long as the steam generators behave similarly. The hot and cold leg nodalization is adequate for representing single phase natural circulation and the choice of high point hot leg nodes allows steam to collect at the high points if primary side steam generation is predicted. The fine nodalization in the steam generators is adequate to represent primary side cooling that drives natural circulation with ASW injection into the steam generators. A detailed pressurizer model is not used, but the inspectors concluded the model was sufficient for predicting the approach to solid operation. The inspectors noted that pressurizer modeling is not important during solid operation.

The licensee provided calculations based upon conservative decay heat generation rate assumptions with SSF operation initiated 14 minutes after event occurrence. They also discussed the results obtained by assuming a realistic decay heat generation rate with SSF operation initiated 12 minutes after event occurrence. The conservative decay heat generation rate was predicted with the American Nuclear Society (ANS)-5.1, 1979 "plus two sigma" model. As illustrated in Information Notice 96-39, options contained in the ANS-5.1, 1979 standard can affect predictions by 10 percent or more. The licensee modeled irradiation history assuming full power operation between refueling outages with what it described as a conservative number of days for outages. To assess the effect of this and the other licensee assumptions, the inspectors compared licensee predicted decay heat generation rates to several other calculations. The inspectors found the licensee's predictions were comparable with the ANS - 5.1, 1979 standard assuming full power operation for three years, and were greater than 10 percent above typical ANS-5.1, 1979 standard values with no uncertainty allowance.

The inspectors judged that the conservative-based calculations were conservative when predicting the initial heatup and they were conservative for predicting the water solid pressurizer operation that follows, assuming SSF operation proceeds as anticipated. The realistic-based calculations were judged to provide a good prediction of RCS heatup for the assumed event. The inspectors concluded that the RETRAN model was acceptable for predicting SSF-associated behavior for the initial transient and the following pressurizer water solid operation.

iv. Use of Indicated Pressure for SSF Control

The licensee plans to initially control RCS pressure between an indicated range of 1950 psig to 2250 psig during the initial response to events requiring use of the SSF. Later, as RCS temperature decreases to and is controlled at 555°F, this pressure control band can be expanded to 1600 psig to 2250 psig. The licensee stated the pressure instrument uncertainty was less than ±150 psi. Thus, actual RCS pressure would be controlled at greater than 1800 psig but less than 2400 psig. The 2400 psig maximum pressure is less than the anticipated opening pressure for a safety valve. The inspectors concluded the maximum pressure stipulation was therefore adequate.

It would be desirable to directly control RCS subcooling to ensure continued natural circulation. However, the licensee did not use this approach because it judged the combined uncertainty in temperature and pressure instrumentation would overly restrict the pressure range available for operator control. Additionally, they expressed concern for over-complicating the actions taken by the operators. Instead, they elected to rely on the RETRAN analysis results to obtain an acceptable lower-bound pressure for control purposes. The licensee's conservative-based and realistic-based RETRAN analyses predicted a minimum subcooling margin of 1°F and 10°F, respectively, when RCS minimum pressure is near 1800 psig. The inspectors concluded the calculated subcooling margin was sufficient to compensate for instrument uncertainty when the SSF is operated near the minimum pressure, until a permanent correction is made for the pressurizer heater deficiency.

.2 Simulator Modeling

a. Inspection Scope

The inspectors investigated the fidelity with which the simulators reproduce pressurizer water solid operations.

b. Observations and Findings

The licensee described the Oconee simulator as ANS/ANSI-3.5, 1985, standard compliant and stated it is maintained in accordance with that standard. The simulator has been in use for 19 years and numerous upgrades have been performed, including incorporation of the Westinghouse SIMARC-4 models of the core, RCS, and steam generators. Similar upgrades have been implemented at DEC's McGuire and Catawba Nuclear Stations, which occasionally require the pressurizer to operate in a water solid condition. The SSF simulator was described as a part-task simulator that runs the same computer code and software as the full-scope simulator.

The inspectors briefly reviewed the modeling assumptions and nodalization used by the Oconee simulator. The inspectors did not identify any modeling characteristics that would preclude application of the simulator model to solid operation for training purposes.

The licensee identified 19 best estimate benchmark transients it used to verify simulator performance. The inspectors noted a wide variety of conditions were covered, but none were similar to the solid operation contemplated for SSF operation. The licensee also stated that it had benchmarked the SSF simulator against RETRAN data and concluded the SSF simulator was a positive training tool. The inspectors did not specifically compare these SSF and RETRAN predictions, although they did observe several applications of the SSF simulator to predict system response during initiation and operation of the SSF. The observed responses were qualitatively consistent with RETRAN predictions, with inspector expectations, and with the inspectors's independent calculation of RCS response to water addition and temperature change during solid operation. (See paragraph .5 below for additional discussion of operator training.)

The inspectors concluded that the SSF simulator was adequate (1) for operator training and (2) for estimation of the timing and response of plant behavior when control is provided from the SSF.

.3 Problem Investigation and Safety Evaluation

a. Inspection Scope

The inspectors reviewed PIP O-02-01066 to assess the licensee's investigation of the SSF pressurizer heater capacity. The inspectors also reviewed the licensee's 10 CFR 50.59 safety evaluation of Abnormal Procedure (AP) AP/0/A/1700/025, "Standby Shutdown Facility Emergency Operating Procedure," Revision 21.

b. Observations and Findings

The licensee's investigation was just beginning when the site visit was conducted. An investigation team from the GO was being established and thus root cause had not been identified for the inspector's review. However, the licensee had completed an operability evaluation consistent with the guidance given in Generic Letter 91-18.

The inspectors reviewed the licensee's 10 CFR 50.59 analysis. This evaluation concluded that increased operation of the SSF letdown valve (HP-428) was acceptable for both thermal cycling and increased duty. The licensee's analysis calculated the letdown valve would be operated once every 27 minutes, assuming a reactor coolant makeup rate of 29 gpm (maximum capacity of the reactor coolant makeup pump). The analysis determined the letdown piping could accept the thermal cycles provided the valve was opened at least once every 1.3 hours. The analysis also determined the valve did not exceed the duty cycle limits if it was stroked less than once every 22 minutes. Based on their review, the inspectors concluded the licensee's safety evaluation sufficiently addressed the items required by 10 CFR 50.59.

.4 Operating Procedure Reviews

a. Inspection Scope

The inspectors reviewed AP/0/A/1700/025, Revisions 20 and 21, to determine whether the changes made as a result of the degraded or nonconforming condition of the pressurizer would be successful in controlling RCS pressure sufficient to maintain RCS subcooling margin following events that require use of the SSF.

b. Observations and Findings

Revision 20 to AP/0/A/1700/025, which was in effect before discovery of the pressurizer heater problems, provided the following general method for initially operating a unit when the SSF was required. Essentially a steam bubble is maintained in the pressurizer to control RCS pressure and heat is removed from the RCS by steaming the stream generators to atmosphere.

- Switch supplies for SSF powered plant equipment from plant power to SSF power.

- Start the SSF diesel generator and begin supplying SSF power with the diesel.

- Start the ASW pump and provide cooling water to the steam generators on each affected unit to stabilize RCS pressure less than or equal to 2300 psig.

- Start the reactor coolant makeup (RCMU) pump on each affected unit and isolate the power operated relief valve (PORV), pressurizer sample, seal return, and letdown lines.

- Energize pressurize heaters (powered from the SSF) as necessary to control RCS pressure at approximately 2150 psig.

- Throttle the ASW flow to keep RCS pressure and temperature slowly decreasing and pressurizer lever greater than or equal to 105 inches.

- When RCS cold leg temperature reaches 555°F, throttle ASW flow to establish a steam generator level between 240 inches and 260 inches.

- When RCS cold leg temperature reaches 555°F, establish a letdown path to control pressurizer level.

Following discovery of the pressurizer heater problems, the licensee issued Revision 21 to AP/0/A/1700/025 which provided the following basic changes. In this case, the operator's actions essentially establish a water solid condition in the pressurizer to control RCS pressure while heat is still removed by steaming the steam generators to atmosphere. To mitigate the affects of ambient heat loss from the pressurizer, the RCMU pump is started and the pressurizer heaters energized earlier in the procedure.

- Start the ASW pump.

- Start the RCMU pump (rather than establishing cooling flow to the steam generators immediately).

- Isolate the pressurizer sample, seal return, and letdown lines (not the PORV).

- Energize the pressurizer heaters (powered from the SSF).

- Establish ASW flow to the steam generators to reduce RCS pressure less than or equal to 2250 psig.

- Isolate the PORV.

- Throttle ASW flow to stabilize RCS pressure between 1950 psig and 2250 psig.

- When RCS cold leg temperature reaches 555°F, periodically establish letdown as necessary to maintain an expanded, RCS pressure band of 1600 psig to 2200 psig (rather than establishing letdown to control pressurizer level).

- Finally, throttle ASW flow to maintain steam generator level between 240 inches and 260 inches.

In both revisions of the procedure, the reactor would be maintained in this steady-state condition until sufficient repairs could be made to the plant to allow reactor cooldown to Cold Shutdown conditions, approximately 72 hours following the event.

The inspectors noted the SSF emergency procedure lacked contingency actions for predictable equipment failures or other problems which could be encountered during SSF operation. For example, AP/0/A/1700/025 specifies the required steps for starting the RCMU pump (i.e., place the OVERRIDE RC MAKEUP PUMP switch to start). Should this switch fail, the operators could manually start the RCMU pump by opening three suction and discharge valves, then place the pump's START switch to run. However, this alternative method for starting the RCMU pump was not provided in the "Response Not Obtained" column. The licensee entered this issue into their corrective action program as PIP O-02-01321.

The inspectors did not identify any technical errors in the revised emergency procedure which would prevent achieving and maintaining stable RCS pressure control using the pressurizer in a water solid condition. Based on this review, combined with operator performance using the revised procedure on the SSF simulator (as discussed below), the inspectors concluded that the procedure changes implemented by Revision 21 would be successful in controlling pressure sufficient to maintain the RCS subcooled following SSF events.

.5 Operator Training

a. Inspection Scope

The inspectors interviewed the training instructors and observed a demonstration of the use of AP/0/A/1700/025, Revision 21, on the simulator to determine whether or not training was sufficient for licensed operators to successfully implement the new procedure. The demonstration was limited to the initial portion of the procedure and included starting the SSF diesel generator, starting the ASW pump, starting the RCMU pump, isolating systems that would reduce RCS inventory and controlling RCS pressure between 1950 psig and 2250 psig with ASW flow to the steam generators. It did not include establishing letdown flow as a means of controlling pressure when RCS cold leg temperature reached 555°F, an action that would typically occur about four hours into the event.

b. Observations and Findings

The licensed operators have a time critical action to start the SSF diesel generator, start the ASW pump and initiate feedwater flow to the steam generators within 14 minutes of a loss of total feedwater event requiring SSF operation. The basis for this action is twofold: to reduce RCS pressure below the PORV lift setpoint and to initiate steam generator cooling before RCS temperature increases to the saturation point. Accomplishing this task within 14 minutes minimizes the loss of RCS inventory and assures an adequate subcooling margin.

During the demonstration, the licensed operator was able to accomplish the above time critical action within 14 minutes. The operator was also successful in controlling RCS pressure between 1950 psig and 2250 psig. The inspectors noted that indications of natural circulation, i.e. the difference between hot and cold leg temperatures and difference between hot leg and core exit temperatures, were consistent with the procedure. The inspectors also noted that, while changes in RCS temperature did affect RCS pressure, the pace of change was slow enough to allow the operator to adequately control RCS pressure within the prescribed operating band. However, because the RCS pressure operating band was narrow, increased operator diligence was required.

The inspectors later asked for a demonstration of RCS pressure control using letdown flow. This action would not be performed until about four hours after the event and, therefore, was not included as part of the licensed operator SSF simulator training provided in response to this issue. The licensed operator demonstrated the ability to establish letdown flow but was not proficient at performing the procedural steps for controlling RCS pressure. The procedure directed RCS pressure be controlled by either fully opening or fully closing the letdown valve. In contrast, the operator attempted to control pressure by throttling the letdown valve in conjunction with throttling the ASW flow. This operator response was similar to that required by the previous procedure revision (20) and highlighted reduced familiarity with the operator actions following the first 15 minutes of SSF operation. The licensee explained that letdown operations had been discussed with all operators and that additional SSF simulator training would be available before letdown operations began in the case of an actual SSF event. The licensee documented the need to review operator performance in PIP O-02-01321.

The inspectors concluded that the training was adequate for operators to implement the revised procedure.

4OA6 Management Meetings

Exit Meeting Summary

The team leader presented the inspection results to Mr. W. R. McCollum and other members of licensee management on March 21, 2002. The licensee's management acknowledged the findings presented.

The licensee's representatives were aware that some proprietary information had been reviewed by the inspectors, however, no proprietary information is contained in this report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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S. Batson, Mechanical/Civil Engineering Manager
E. Burchfield, Design Basis Manager
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N. Clarkson, Regulatory Compliance
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R. Jones, Station Manager
S. Kumar, IT Professional
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W. McCollum, Site Vice President, Oconee Nuclear Station
K. Moses, Operations
L. Nicholson, Regulatory Compliance Manager
P. Stovall, Operations Training Supervisor
G. Swindlehurst, Section Manager, Safety Analysis, Nuclear Generation Dept.
W. Vassey, Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

None

LIST OF ACRONYMS

AC	Alternating Current
ANS	American Nuclear Society
AP	Abnormal Procedure
ASW	Auxiliary Service Water
B&W	Babcock and Wilcox
COLR	Core Operating Limits Report
DEC	Duke Energy Corporation
F	Fahrenheit
FT	Feet
GO	General Office, DEC
GPM	Gallons per Minute
IP	Inspection Procedure
IR	Inspection Report
kW	Kilowatts
LER	Licensee Event Report
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PIP	Problem Investigation Process
PORV	Power Operated Relief Valve
PSIG	Pounds per Square Inch Gauge
RCS	Reactor Coolant System
RCMU	Reactor Coolant Makeup
SSF	Standby Shutdown Facility
UFSAR	Updated Final Safety Analysis Report

LIST OF DOCUMENTS REVIEWED

Procedures

AP/1,2,3/A/1700/025, "Standby Shutdown Facility Emergency Operating Procedure," Rev 20

AP/1,2,3/A/1700/025, "Standby Shutdown Facility Emergency Operating Procedure," Rev 21

OP/0/A/1102/024 (Draft), "Plant Assessment and Alignment Following Major Site Damage," Rev 24

OP/0/A/1102/025 (Draft), "Cooldown Following Major Site Damage," Rev 15

IP/0/A/0200/037A, "Pressurizer Heater Group B Surveillance," Rev 02

IP/0/B/0200/037, "Pressurizer Heater Test and Surveillance," Rev 49

IP/0/B/3000/020, "PM of Self-Contained Battery Packs On Emergency Lights," Rev 27

Simulator Exercise Guides

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-8931

MEMORANDUM TO: D. Charles Payne
Team Leader
Special Inspection Team

FROM: Luis A. Reyes **/RA/**
Regional Administrator **3/18/2002**

SUBJECT: SPECIAL INSPECTION TEAM CHARTER

A Special Inspection Team (SIT) has been established to inspect and assess the degraded condition of the Oconee Standby Shutdown Facility (SSF) as reported by the licensee on March 7, 2002. The specific issue of concern is: Will the SSF perform its design basis function with the licensee's compensatory measures?

The team composition is as follows:

Team Leader: C. Payne (RII)

Team Members: S. Freeman (RII)
W. Lyon (NRR)

The objectives of the inspection are to: (1) determine the facts surrounding the degraded condition of the Oconee SSF; (2) evaluate the licensee's response to this condition; and, (3) assess the generic aspects of the degraded condition and any operational issues.

For the period during which you are leading this inspection and documenting the results, you will report directly to me. The guidance of NRC Inspection Procedure 93812, "Special Inspection," and Management Directive 8.3, "NRC Incident Investigation Procedures," apply to your inspection. If you have any questions regarding the objectives of the attached charter, contact me.

Attachment: SIT Charter

cc w/attachment:
W. Kane, DEDR
S. Collins, NRR
H. Berkow, NRR
R. Correia, NRR
M. Shannon, RII
C. Casto, RII

SPECIAL INSPECTION TEAM CHARTER
OCONEE NUCLEAR STATION
STANDBY SHUTDOWN FACILITY DEGRADED CONDITION

Basis for the formation of the SIT - The licensee determined that the capacity of the pressurizer heaters which are supplied power from the standby shutdown facility (SSF) may be insufficient to compensate for heat losses from the pressurizer during events where the SSF is used to achieve safe shutdown. As a compensatory action, the licensee modified the SSF operating procedure to establish water solid conditions in the pressurizer as a means for controlling reactor coolant system (RCS) pressure sufficient to maintain RCS subcooling margin. This condition appears to have the characteristics which meet the criteria of Management Directive 8.3 in that the previous method for operating the pressurizer exceeded the design basis of the facility.

Associated with the degraded condition of the Oconee SSF, the specific issue of concern is: Will the SSF perform its design basis function with the licensee's compensatory measures? Accordingly, the objectives of the inspection are to: (1) determine the facts surrounding the degraded condition of the Oconee SSF; (2) evaluate the licensee's response to this condition; and, (3) assess the generic aspects of the degraded condition and any operational issues. To accomplish these objectives, the following will be performed:

- Assess the revised SSF abnormal operating procedure AP/1,2,3/A/1700/025 to determine the likelihood of success when using the new RCS pressure control strategy

- Assess the licensed operators' training and capability to successfully implement the revised SSF abnormal operating procedure to maintain the reactor stable in hot standby for a period of 72 hours

- Assess the procedural guidance and operator training and capability for transferring the reactor from hot standby conditions using water solid pressurizer pressure control to cold shutdown conditions

- Assess the thermo-hydraulic analysis performed to justify the feasibility of the revised operating methodology including the impact of temperature and pressure transients on core cooling

- Assess the licensee's activities related to the problem investigation performed to date (e.g., root cause analysis, extent of condition, additional equipment failure mechanisms, etc.)

- Assess the licensee's safety evaluation of the compensatory measures

- Assess the potential generic aspects of inadequate pressurizer heater capacity to balance ambient heat losses

- Document the inspection findings and conclusions in an inspection report within 30 days of the inspection

- Conduct an exit meeting