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

June 29, 2000

Duke Energy Corporation
ATTN: Mr. H. B. Barron
Vice President
McGuire Nuclear Station
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

SUBJECT: MCGUIRE NUCLEAR STATION - NRC SPECIAL INSPECTION REPORT NO. 50-369/00-08

Dear Mr. Barron:

On May 30, 2000, through June 17, 2000, the NRC completed a special inspection at your McGuire Nuclear Station. The enclosed report presents the results of this inspection. The results were discussed on June 14, 2000, with you and other members of your staff.

The inspection was performed as a result of implementation of guidance contained in NRC Management Directive 8.3, NRC Incident Investigation Procedures, which provides decision-making criteria for NRC management to determine when inspections beyond the routine baseline inspection program are warranted. In this case, operational performance during the May 25, 2000, Unit 1 automatic reactor trip resulted in a risk increase sufficient for this special inspection.

Based on the results of this inspection, we have determined that the cause of the reactor trip was well understood and appropriate safety systems responded as designed. However, the inspection also identified several operator performance and training issues which were placed in your corrective action program.

The NRC identified one operator performance issue that was evaluated using the significance determination process and determined to be of very low safety significance (Green). This issue was determined to involve a violation of NRC requirements. However, the violation is not cited due to its very low safety significance and because it has been entered into your corrective action program. If you contest this non-cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the McGuire facility.

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 Publically Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Reading Room).

Sincerely,

/RA/

Charles R. Ogle, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket No. 50-369
License No. NPF-9

Enclosure: NRC Special Inspection Report
w/Attached Special Inspection Charter and NRC's Revised Reactor Oversight Process

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-369
License No:	NPF-9
Report No:	50-369/00-08
Licensee:	Duke Energy Corporation
Facility:	McGuire Nuclear Station, Unit 1
Location:	12700 Hagers Ferry Road Huntersville, NC 28078
Dates:	May 30 - June 17, 2000
Inspectors:	S. Shaeffer, Special Inspection Leader, Senior Resident Inspector, McGuire M. Franovich, Resident Inspector, McGuire M. Ernstes, Operator Licensing Examiner, Region II
Approved by:	C. Ogle, Chief, Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

<u>Adams Template:</u>

NRC Inspection Report 50-369/00-08, Duke Energy Corporation, McGuire Nuclear Station, Unit 1, conducted between May 30 and June 17, 2000. This inspection, conducted in the Special Inspection area, reviewed the facts surrounding the Unit 1 reactor trip on May 25, 2000, and assessed the licensee's operational performance before and after the trip. The inspection was conducted by resident inspectors and a regional operations specialist. This inspection identified one green issue which was a non-cited violation. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the NRC's Significance Determination Process.

Cornerstone: Mitigating Systems

- Green. A non-cited violation of Technical Specification 5.4.1.a was identified for two examples of the licensee's failure to follow the emergency procedure generic enclosure used for maintaining auxiliary feedwater (CA) suction sources during reactor trip recovery. This resulted in the inadvertent isolation of the preferred CA suction supply and actuation of the service water system to provide CA to the steam generators. A lack of training and familiarity with the applicable emergency procedure generic enclosure was found to be a contributor to this finding. The safety significance of this violation was very low because the CA system was able to perform its function of steam generator decay heat removal (Section 04.03).

Report Details

01 Special Inspection Team Charter

On May 30, 2000, a special inspection was established by NRC Region II management using the guidance contained in Management Directive 8.3, NRC Incident Investigation Procedures. The special inspection was chartered to inspect and assess the circumstances associated with a Unit 1 reactor trip and subsequent inadvertent alignment of nuclear service water (RN) to the steam generators (SGs) that occurred on May 25, 2000. Utilizing Inspection Procedure 93812, Special Inspection, the inspection focused on the activities outlined in the attached special inspection charter. Reviews of these areas are outlined below. NRC Inspection Report 50-369,370/00-04, will review other aspects of this event including the root cause evaluation for the inverter output switch failure and restart evaluations.

02 Risk Significance of the Event

The initial risk significance assessment by the Region II senior reactor analysts indicated that there was sufficient risk increase to consider the event for more than the baseline inspection program. The major contributors to risk increase were the introduction of potential common-mode failure mechanisms (i.e., air binding or introduction of foreign material from RN supplies) when all but the RN system was rendered unavailable as the water source to the auxiliary feedwater (CA) pumps. Operational performance questions before and after the trip, in conjunction with the increase in risk, led to NRC Region II management's decision to conduct a special inspection.

03 Event Description

03.01 Event Summary

On May 25, 2000, at 8:46 p.m., while Unit 1 was operating at 100 percent power, a reactor trip occurred due to an actual low-low water level condition in SG C. The event was initiated at 8:43:30 p.m. by the failure of Channel 1 vital 120 volt alternating current (AC) power due to the opening of the 1EVIA inverter AC output switch. No testing or other contributing activities were in progress at the time the output switch failed open.

The loss of inverter power caused a turbine impulse pressure channel to fail low, which in turn, caused control rods to automatically insert. Nine seconds after the loss of Channel 1 vital 120 volt AC power, the reactor operator took control rods to manual and stopped automatic rod insertion. The loss of the inverter power also resulted in all Channel 1 SG level instruments failing low. As Channel 1 of the SG level instruments was selected as the controlling channel, the main feedwater (MFW) regulating valves (RV) responded accordingly and traveled toward full open and the MFW pumps went to full speed. This resulted in an actual increase in SG water levels. Thirteen seconds later, the reactor operators (ROs) selected Channel 2 of steam generator water level as the controlling channel. With the failed channel now removed from the SG level control logic, the MFW RVs went full closed due to SG water levels above the program. These secondary perturbations resulted in the automatic starting of an idle condensate booster pump (CBP) and hotwell pump (HWP), as well as eventually tripping the 1A MFW pump due to high discharge pressure.

Twenty seconds later, a turbine runback occurred due to the loss of the 1A MFP, at which time the reactor operator at the controls (OATC) returned the control rods back to auto. The control rods inserted in auto at maximum speed (since turbine impulse pressure had failed low) for about one minute. This action was expected for the runback condition. The control room senior reactor operator (CRSRO) then directed that the rods should be placed back in manual in accordance with the loss of inverter abnormal procedure AP/1/A/5500/15 (AP-15), Loss of Vital or Aux Control Power. At this time, reactor power was approximately 80 percent and the main turbine had completed a runback to 50 percent. Approximately 1 minute later, SG levels decreased to the point that a reactor trip occurred at 8:46 p.m.

The unit was stabilized in Mode 3 with decay heat removal by the CA system which automatically injected to all SGs. During the reactor trip, motor-driven (MD) CA pump 1A failed to automatically start. Operators immediately recognized this and manually started the pump from the control room. The inspector confirmed that the failure of the pump to automatically start following the reactor trip was expected due to the automatic start circuit being deenergized when the output switch of the EVIA inverter failed. Approximately 70 minutes after the trip, two distinct errors in implementing the emergency procedure generic enclosure were made by the operators. These errors resulted in the momentary isolation of the preferred CA sources and swap-over to the assured, RN source. This was recognized immediately by the operators and corrected. The unit remained in Mode 3 until it was placed back in service on May 26. No findings were identified.

03.02 Sequence of Events - Unit 1 Reactor Trip/Loss of 1EVIA Event - May 25, 2000

The inspectors determined the following sequence for the event.

Time (p.m.)	Event
8:43:30	1EVIA inverter AC output switch fails to off position, deenergizes vital panel board 1EKVA causing loss of all Channel 1 indications for SG level control (all four SGs)
8:43:35	MFW RVs go full open in response to indicated low SG levels on the controlling channels.
8:43:39	Control rods placed in manual per AP-15 immediate action
8:43:39	Low MFW suction pressure alarm due to MFW RVs full open
8:43:39	CBP low suction pressure alarm - 1C CBP auto start and 1A HWP automatically started

8:43:43	ROs select SG level control to Channel 2 - MFW RVs go closed or near closed due to SG levels being high and the controller trying to restore programmed level
8:43:59	1A MFW pump trips on high discharge pressure since all CBPs and HWPs are running and MFW RVs are near closed (Note: 1B MFW pump within 3 psig of tripping, but does not trip) Turbine runback to 50 percent due to MFW pump 1A trip
8:43:59	OATC returns control rods to auto per immediate action of AP/1/A/5500/03 (AP-03), Load Rejection
8:44:02	MFW RVs begin to open due to loss of flow from 1A MFW pump trip
8:44:23	Primary power operated relief valves 1NC32 and 1NC36 open to control primary pressure
8:45:00	Control rods placed in manual per AP-15, Step 1 (reactor power approximately 80 percent, turbine power 50 percent)
8:46:00	1C SG Lo Lo level - reactor trip/enter emergency procedure EP/1/A/5000/E-O
8:46:11	CA MD pump B automatically starts
8:46:31	CA turbine driven (TD) automatically starts
8:46:53	CA MD pump A manually started
8:56:00	SG levels restored - CA pumps recirculating to upper surge tanks (USTs) - unit stabilized in Mode 3
9:27:58	USTs isolated by closing valve 1CS-18
9:57:19	CA condensate storage tanks (CACSTs) isolated by closing valve 1CA6 (CACSTs level <20 percent)
9:57:29	RN supply automatically aligned to CA pump suctions due to low suction pressure
9:58:22	ROs reopened valve 1CA6 and RN supply to CA closed (except standby shutdown facility (SSF) RN supply)
9:58:27	Plant operators aligned 1KRP alternate power source to inverter 1EVIA
10:09:17	USTs unisolated by opening valve 1CS-18

10:26:37 RN SSF supply closed at SSF control panel

03.03 Independent Verification Reviews of Event Timeline

The inspectors performed a detailed, independent review of the event trip report, plant operating data, operating logs, and operator aid computer (OAC) information, as well as conducted interviews with numerous personnel, to confirm the sequence of events both before and after the reactor trip. During this review, the inspectors also verified the apparent cause of the event and the impact of the loss of power from the EVIA vital inverter with regard to the scope of this inspection. No findings were identified.

04 Operator Performance Issues

04.01 Manipulation of Control Rods During the Event

The inspectors reviewed the three manipulations of rod control during the event to determine if the operator actions were appropriate and in accordance with applicable procedures. The event started with the failure of the inverter output switch that deenergized Channel 1. This caused a channel of the turbine impulse pressure to fail low, which caused control rods to automatically insert. Nine seconds after the loss of Channel 1, the OATC took control rods to manual and stopped automatic rod insertion. This is an immediate action step of AP-15, and was appropriate.

Twenty seconds later, a turbine runback occurred due to the loss of MFP 1A. At this time, the OATC took rods back to auto. This was in accordance with Step 2 of AP-03, which says to check control rods in auto and moving as required. This step is an immediate action step which was to be performed immediately from memory. Rods inserted in auto at max speed (since impulse pressure had failed low) for about one minute. Taking rods to auto was appropriate for the runback condition.

At this time, the CRSRO pulled out AP-15 and read Step 1, which stated "Check 'TURB IMP PRESS CH1'- NORMAL," he then directed the OATC to place rods back in manual in accordance with the procedure. The OATC placed rods in manual and did not insert them. Reactor power was about 80 percent and the main turbine had completed a runback to 50 percent. Based on the reviews performed, the inspectors acknowledged that the abnormal operating procedures are event specific and not designed to be performed concurrently. There was a conflict between the two procedures in effect. AP-15 directed the rods be placed in manual and AP-03 directed the rods be in auto. The crew could not resolve the conflict between the two procedures and elected to place rods in manual with a 30 percent disparity between reactor and turbine power. The inspectors concluded that although no violation of procedural requirements was identified, it would have been more prudent to delay placing the rods in manual or place the rods in manual and insert the rods as necessary to better cope with the power mismatch which existed at the time. Based on the above, no findings were identified.

04.02 Adequacy of Method Used to Select SG Level Controlling Channel

The inspectors reviewed the procedural requirements to select an alternate channel for SG level control when the controlling channel is affected by the loss of vital instrument power. Operator actions were also reviewed and discussed with the operators who implemented the procedure during the event. Industry operating experience was reviewed for potential applicability. Control room simulator fidelity and training materials were also reviewed.

When the output switch failed on vital inverter 1EVIA, the controlling SG narrow range water level instruments (i.e., Channel 1 was selected for all four generators) were de-energized and failed to zero level. This false low SG level condition caused the MFW RVs to travel nearly 100 percent full open and the MFW pumps to increase speed. Approximately thirteen seconds later, the ROs selected SG level Channel 2 for each SG as the controlling channel. Selecting an alternate channel is the second immediate action step of AP-15. In that 13 seconds, the SG levels had increased from about 65 to 67 percent. A feedwater isolation occurs at 83 percent (P-14 setpoint for Hi Hi SG level). Operators stated that during simulator training on the same event, selecting an unaffected channel without going to manual on the MFW RVs had consistently terminated the transient, and the MFW pumps did not trip. The inspectors determined that the operators correctly selected Channel 2 for all four steam generators in a timely manner and in accordance with AP-15.

During simulator observations of this event, the inspectors observed that a loss of vital power panel board EKVA (powered from vital inverter EVIA) results in the MFW RVs going from a normal position of approximately 50 percent open to near 80 percent open. Slight variation in MFW pumps' speed and discharge pressure occurred. However, when SG level control was selected to Channel 2, the MFW RVs did not go near full closed nor did the MFW pumps approach the high discharge pressure trip setpoint. This difference between the response of the simulator and the plant was entered into the licensee's corrective action program following the May 25, 2000, reactor trip. The inspectors concluded that the MFW RVs response during simulator training for the loss of 1EKVA panel board was not reflective of actual plant response.

With respect to the AP-15 steps to immediately select an operable channel, the inspectors noted that AP/1/A/5500/06, Loss of SG Feedwater, directs operators to place the MFW RVs in manual; restore SG level to program level; and then select an operable channel. The licensee was evaluating potential improvements to limit the effect of this event on the unit. No findings were identified.

04.03 <u>Isolation and Restoration of CA Sources</u>

During implementation of post-reactor trip recovery procedures, operators implemented EP/1/A/5000/G-1, Enclosure 20, Maintaining CA Suction Sources.

About 45 minutes after the reactor trip, the operations shift manager (OSM) gave the OATC Enclosure 20 to monitor CA suction sources. Step 4 read:

> <u>IF</u> <u>AT</u> <u>ANY</u> <u>TIME</u> UST level is less than 3 feet, <u>OR</u> if all UST level indication is lost (control room and local), <u>THEN</u>...

The USTs were full because CA was recirculating back to the tanks. The OATC questioned the validity of the full UST levels indicated in the control room. The OSM told the OATC that the tanks were full and to continue with the procedure. The OATC correctly answered the IF/THEN statement; however, he incorrectly continued with substeps 4.a and 4.b. He directed a non-licensed operator to shut valve 1CS-18, which isolated the USTs as a suction source for the CA pumps. This mispositioning of valve 1CS-18 is identified as the first example of a failure to follow the requirements of EP/1/A/5000/G-1, Enclosure 20.

Thirty minutes after 1CS-18 was closed, a second reactor operator, the balance of plant (BOP) RO, performed Step 5 of Enclosure 20. He did not correctly perform the second bullet of Step 5.a which said to:

> “Check if UST is aligned to CA pump suction”

In fact, the UST was isolated by the previously shut 1CS-18. The BOP RO failed to detect that 1CS-18 was shut. The BOP RO then closed 1CA-6 (CA supply from CACST). With USTs and CACSTs isolated, the RN-to-CA valves opened and RN was pumped into the SGs. The crew immediately recognized the inadvertent isolation of the preferred CA sources and re-opened CA-6. The failure to verify proper UST alignment prior to closing 1CA-6 is identified as the second example of a failure to follow the requirements of EP/1/A/5000/G-1, Enclosure 20. Based on the reviews performed, the inspectors concluded that the realignment back to the preferred CA suction sources was appropriate for the circumstances. The licensee was also planning to review the enclosure for improved guidance in this regard.

TS 5.4.1 requires, in part, that procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, Quality Assurance Program Requirements. This includes emergency procedures to cope with plant events. The failure to follow emergency procedure EP/1/A/5000/G-1, Enclosure 20 in the two examples described above, is in violation of TS 5.4.1. This violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as Problem Investigation Process (PIP) report M-00-1900 and is identified as NCV 50-369/00-08-01: Failure to Follow Emergency Procedure Concerning Auxiliary Feedwater Suction Supplies. The safety significance of this violation was very low because the CA system was able to perform its function of steam generator decay heat removal.

05 <u>Confirmation of CA Inventory Response</u>

05.01 <u>CA System Inventory Response</u>

The inspectors independently reviewed the system performance during the event, focusing on the water suction supplies to the three Unit 1 CA pumps. Plant computer data, the OAC transient monitor report, design basis information, operator logs, and other information were used in the evaluation. The CACST and UST water levels, SG levels, CA pump flows, and RN supply valves stroke times were also assessed. Plant operators, the CA system engineer, and the RN system engineer were interviewed. The inspectors determined that the CA system and RN supply performed as expected with no noted anomalies. No findings were identified.

06 Management Meetings

The inspectors presented the inspection results to Mr. B. Barron and other members of licensee management at the conclusion of the inspection on June 14, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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Bradshaw, S., Superintendent, Plant Operations
Byrum, W., Manager, Radiation Protection
Cash, M., Manager, Regulatory Compliance
Dolan, B., Manager, Safety Assurance
Evans W., Security Manager
Geer, T., Manager, Civil/Electrical/Nuclear Systems Engineering
Jamil, D., Station Manager, McGuire Nuclear Station
Patrick, M., Superintendent, Maintenance
Peele, J., Manager, Engineering
Loucks, L., Chemistry Manager
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical Systems Engineering

NRC

W. Rogers, Region II Senior Reactor Analyst

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed During this Inspection

50-369/00-08-01	NCV	Failure to Follow Emergency Procedure Concerning Auxiliary Feedwater Suction Supplies (Section 04.03)

Special Inspection Charter
McGuire Nuclear Station
Unit 1 Reactor Trip of May 25, 2000

The objectives of the inspection are to determine the facts surrounding the Unit 1 reactor trip on May 25, 2000, and assess the licensee's operational performance. To accomplish this objective, the following will be performed:

1. Review, and to the extent practical, confirm key elements of the licensee's timeline of the event.

2. Conduct a review of operator performance during this event. Specifically review:

   - positioning of rod control between automatic and manual
   - adequacy of the method used to swap between controlling channels of steam generator water level
   - operator actions to isolate the preferred sources of auxiliary feedwater (AFW), as well as operator actions to restore the preferred AFW source following swapover to service water

   This review should include procedural adherence on the part of the operators; the adequacy of the underlying procedures; and operator command and control during the event.

3. In addition, review AFW inventory response during the event. Include a review of the time response as related to the levels of major sources of preferred AFW inventory following the initiation of AFW.

4. Document the inspection findings and conclusions in an inspection report within 30 days of the completion of the inspection.

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.