May 14, 2001

Mr. Oliver D. Kingsley, President
Exelon Nuclear
Exelon Generation Company, LLC
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: LASALLE COUNTY STATION UNIT 2
NRC SPECIAL INSPECTION REPORT 50-374/01-09(DRP)

Dear Mr. Kingsley:

On April 11, 2001, the NRC completed a Special Inspection at your LaSalle County Station. The enclosed report presents the results of that inspection. The results of this inspection were discussed on April 13, 2001, with Mr. M. Schiavoni and other members of your staff.

On April 6, 2001, LaSalle Unit 2 automatically scrammed from 100 percent power. Your initial investigation determined that a blown fuse in the feedwater control system caused by a maintenance activity initiated a sequence of events which led to the scram. Some equipment performance problems were noted subsequent to the reactor scram. Following the scram, the motor-driven reactor feedwater regulating valve could not initially be opened. This rendered the motor-driven reactor feedwater pump unavailable until operators manually re-aligned the system for use. The turbine-driven reactor feedwater pumps had tripped, which presented the operators with a total loss of normal feedwater scenario. In addition, after operators manually initiated the Reactor Core Isolation Cooling (RCIC) system for inventory control, the system operated in an unstable manner in the automatic mode until operators elected to manually operate the system. Also, after the RCIC pump was secured, the inboard and outboard RCIC injection check valves unexpectedly indicated open instead of closed. This required additional actions, including an entry into the drywell, to resolve this problem to allow plant restart. Finally, LaSalle probabilistic risk assessment personnel arrived at an erroneous conclusion regarding the potential risk-significance of the event which significantly differed from that estimated by the NRC Senior Reactor Analyst.

Based on the risk and deterministic criteria specified in Management Directive 8.3, “NRC Incident Investigation Program,” and Inspection Procedure 71153, “Event Followup,” and due to the equipment performance problems which occurred, a Special Inspection was initiated in accordance with Inspection Procedure 93812, “Special Inspection,” to evaluate the facts and circumstances surrounding the event as well as the actions taken by your staff in response to the unexpected system performance issues encountered. The inspection focused on (1) the root cause of the initiating event, including the impact of maintenance activities on plant operations, (2) the potential design vulnerability which allowed a single blown fuse in the feedwater control system to cause a reactor scram, (3) the circumstances surrounding the initial unavailability of the motor-driven reactor feedwater pump, (4) the circumstances surrounding the unstable performance of the RCIC pump during operation in automatic and the corrective actions taken to address this problem prior to plant restart, (5) the circumstances surrounding the unexpected open indication of the RCIC inboard and outboard injection check valves following system shutdown and actions taken to comply with Technical Specification requirements, and (6) initial event risk assessment differences between LaSalle and NRC probabilistic risk assessment personnel.

Based on the results of this inspection, the inspectors identified one issue of very low safety significance (Green) regarding the failure to adequately evaluate the potential consequences of a planned maintenance activity and implement appropriate contingency actions. Following a review of this event, we also determined that design vulnerabilities in the feedwater and RCIC systems were either not recognized, or if recognized, were not formally evaluated for an impact on safety. We also determined that an unexpected material condition problem associated with the RCIC system required the crew's attention during the event, which under different circumstances, may have adversely impacted event response. In addition, a lack of knowledge of Technical Specification requirements led to an incorrect Technical Specification entry. Finally, we determined that your staff initially did not perform an appropriate risk assessment of the event.

Although none of these individual issues are of significant concern by themselves, taken collectively, it appears that a lack of adequate knowledge regarding the design and operating characteristics of the feedwater and RCIC systems, the LaSalle Technical Specifications, and the risk assessment process directly led to the event and other problems encountered during event response activities, which warrants your attention.

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/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/ S. Reynolds

Geoffrey Grant, Director
Division of Reactor Projects

Docket No.: 50-374
License No.: NPF-18

Enclosure: Inspection Report 50-374/01-09(DRP)

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REGION III

Docket No: License No:	50-374 NPF-18
Report No.:	50-374/01-09(DRP)
Licensee:	Exelon Generation Company
Facility:	LaSalle County Station, Unit 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	April 9 through April 11, 2001
Inspectors:	E. Duncan, LaSalle Senior Resident Inspector Michael Parker, Senior Reactor Analyst, RIII Stuart Sheldon, Electrical Engineering Specialist, RIII
Approved by:	Kenneth Riemer, Acting Chief Branch 2 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000374-01-09, on 04/09-04/11/2001, Exelon, LaSalle County Station, Unit 2; Special Inspection.

This special inspection examined the facts and circumstances surrounding a Unit 2 automatic reactor scram which occurred on April 6, 2001, as well as the actions taken by licensee personnel in response to unexpected system performance issues encountered following the scram.

The members of the special inspection staff included the LaSalle Senior Resident Inspector, as well as Region III personnel consisting of a Division of Reactor Safety (DRS) Electrical Engineering Specialist and a Senior Reactor Analyst (SRA). One Green finding was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609 “Significance Determination Process” (SDP). The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html. Findings for which the SDP does not apply are indicated by “No Color” or by the severity level of the applicable violation.

A. Inspector Identified Findings

Cornerstones: Initiating Events and Mitigating Systems

Green. A reactor scram resulted from the failure to adequately evaluate the potential consequences of a maintenance activity associated with the feedwater control system and implement appropriate contingency actions.

The issue was of very low safety significance since sufficient plant equipment was available to place and maintain the plant in a stable condition (Section 1R2).

B. Licensee Identified Findings

No findings of significance were identified.

Report Details

Summary of Plant Event

On April 6, 2001, LaSalle Unit 2 automatically scrammed from 100 percent power. Initial investigations determined that a blown fuse in the feedwater control system caused a downshift of the reactor recirculation pumps. The resultant level swell caused reactor water level to reach the high level trip setpoint and the turbine-driven reactor feedwater pumps (TDRFPs) and main turbine tripped as designed. This resulted in an automatic reactor scram.

Some equipment performance problems were noted subsequent to the reactor scram. Following the scram, the motor-driven reactor feedwater pump (MDRFP) feedwater regulating valve could not be initially opened which rendered the MDRFP unavailable until operators manually re-aligned the system for use. Since the turbine-driven feed pumps had also tripped, the operators initiated the Reactor Core Isolation Cooling (RCIC) system. After operators manually initiated the RCIC system for reactor vessel level control, the system operated in an unstable manner in the automatic mode until operators elected to manually operate the system. After restoring reactor water level and the MDRFP feedwater regulating valve, the RCIC pump was secured, however, the inboard and outboard RCIC injection check valves unexpectedly indicated open instead of closed. In addition, licensee probabilistic risk assessment personnel arrived at an erroneous conclusion regarding the potential significance of the event which significantly differed from that estimated by the NRC Region III Senior Reactor Analyst (SRA).

Based on the risk and deterministic criteria specified in Management Directive 8.3, “NRC Incident Investigation Program,” and Inspection Procedure 71153, “Event Followup,” and due to the equipment performance problems which occurred, a special inspection was initiated in accordance with Inspection Procedure 93812, “Special Inspection.”

The purpose of the inspection was to evaluate the facts and circumstances surrounding the event as well as the actions taken by licensee personnel in response to the unexpected system performance issues encountered. In particular, the inspection focused on the following: (1) the root cause of the initiating event, including the impact of maintenance activities on plant operations, (2) the potential design vulnerability which allowed a single blown fuse in the feedwater control system to cause a reactor scram, (3) the circumstances surrounding the initial unavailability of the motor-driven reactor feedwater pump, (4) the circumstances surrounding the unstable performance of the RCIC pump during operation in automatic and the corrective actions taken to address this problem prior to plant restart, (5) the circumstances surrounding the unexpected open indication of the RCIC inboard and outboard injection check valves following system shutdown and actions taken to comply with Technical Specification requirements, and (6) initial event risk assessment differences between LaSalle and Region III probabilistic risk assessment personnel.

3. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R1 Root Cause Evaluation

a. Inspection Scope

The inspectors reviewed the root cause of the initiating event, including the impact of maintenance activities on plant operations.

b. Findings

One Green finding was identified for a reactor scram which resulted from the failure to adequately evaluate the potential consequences of a maintenance activity associated with the feedwater control system and implement appropriate contingency actions.

Sequence of Events

The inspectors reviewed logs, alarm printouts, and other documentation, interviewed cognizant individuals who responded to the scram, and developed the following sequence of events for the April 6, 2001 Unit 2 reactor scram:

Time	Event Description
08:30	Instrument Maintenance Department (IMD) personnel were performing work activities associated with 2FW146, the MDRFP low flow feedwater regulating valve, in accordance with Work Request (WR) 990265385-01. The controller and valve position indication disagreed and IMD was performing troubleshooting.
09:09:00	Steady-state conditions existed. Feedwater control was stable with no identified problems. The 2A and 2B TDRFPs were operating in 3-element automatic control.
09:09:25	Reactor Vessel Low Level alarm received in the Main Control Room.
09:09:26	2B TDRFP system trouble alarm received. The 2B TDRFP shifted into diagnostic manual resulting in an increase in 2B TDRFP speed. The 2A TDRFP shifted to manual control.
09:09:30	The 2A and 2B reactor recirculation pumps downshifted from fast to slow speed.
09:09:36	Reactor Vessel High Level alarm (+55.5 inches) received. Both the 2A and 2B TDRFPs tripped, resulting in a turbine trip and reactor scram.

09:09:44 Reactor vessel level indicated 12.5 inches. LaSalle Emergency Operating Procedure LGA-01, “RPV [Reactor Pressure Vessel] Control,” entered.

09:10 The Unit 2 MDRFP was manually started to control reactor vessel level. Feedwater regulating valve 2FW005 failed to open which rendered the MDRFP unavailable for injection.

09:12:47 RCIC was manually initiated to control reactor vessel level since the main feedwater system was not initially available. RCIC was identified to be unstable in automatic control. Manual control of RCIC was utilized.

09:15 Lowest reactor vessel level (-46 inches) was recorded.

09:28 The MDRFP feedwater regulating valve was manually opened and injection utilizing the MDRFP begins.

09:31 Reactor vessel water level restored to greater than 12.5 inches.

09:54 RCIC system secured. The RCIC inboard and outboard injection check valves, 2E51-F066 and 2E51-F065, failed to indicate closed.

12:55 RCIC started in accordance with Step E.2 of LaSalle Operating Procedure (LOP) RI-03, “Reactor Core Isolation Cooling System Isolation and System Shutdown,” in an attempt to close 2E51-F065 and 2E51-F066.

13:10 2E51-F065 indicated closed. Secured RCIC system without success to close 2E51-F066.

13:30 RCIC Injection Valve 2E51-F013 and Residual Heat Removal (RHR) head spray discharge header isolation valve 2E51-F023 closed and de-energized.

Root Cause Review

During initial troubleshooting activities, licensee personnel identified that fuse F7 associated with feedwater control system power supply 2C34-K611 blew. After further review, licensee personnel determined that when fuse F7 blew, this caused both reactor recirculation pumps to shift from fast speed to slow speed, resulting in reactor vessel level increasing to the high level setpoint, tripping both TDRFPs, and causing a reactor scram. Additional review determined that maintenance activities associated with 2FW146, the MDRFP low flow feedwater regulating valve, caused a short circuit condition which, in turn, caused the fuse to blow. As a result, the feedwater regulating valve 2FW005 failed closed.

The inspectors interviewed cognizant maintenance personnel and reviewed WR 990265385-01 which controlled the work associated with 2FW146. Following those discussions, the inspectors determined that during the maintenance activity, a lead associated with the 2FW146 valve position transmitter was lifted and taped to cover the exposed connector. However, during subsequent testing activities which re-positioned the valve, the F7 fuse blew. An inspection of the position transmitter identified evidence of an arc strike in the vicinity of the taped lead. The inspectors interviewed Instrument Maintenance Department (IMD) personnel involved with the maintenance activity and determined that the most likely root cause was due to the actuation of the 2FW146 low flow feedwater regulating valve which caused moving components internal to the position transmitter assembly to come in contact with the lifted and energized lead which caused a short circuit and resulted in a fault which caused fuse F7 to blow. Licensee personnel independently reached a similar conclusion with respect to the most likely root cause of the event.

The inspectors reviewed the work package associated with WR 990265385-01 and identified that the work was planned using Work Control Procedure WC-AA-104, "Review and Screening for High Production Risk Activities and Work Authorization," Revision 1. This procedure provided the steps required to screen, plan, and authorize maintenance work activities to minimize the potential for a reactor scram, turbine trip, or lost generation capability. During the review of WR 990265385-01, the inspectors identified that WC-AA-104, Attachment 1, "Plant Impact Screening," indicated that the maintenance activity did not have the potential to cause an actual or potential loss of plant equipment which could result in a scram. As a result, licensee personnel concluded that this activity was not a high production risk activity. The inspectors reviewed this determination and concluded that this assessment was incorrect since a reactor scram occurred as a result of the maintenance activity. The inspectors also concluded that a failure to adequately control the lifted lead to perform the maintenance activity contributed to the event.

Significance Evaluation

The inspectors reviewed this event against the guidance contained in Appendix B, "Thresholds for Documentation," of Inspection Manual Chapter (IMC) 0610*, "Power Reactor Inspection Report." The inspectors determined that with regard to the Group 1 questions in IMC 0610*, the issue had an actual impact on safety since a reactor scram occurred as a result of the failure to adequately evaluate the potential consequences of the maintenance activity and implement appropriate contingency actions. As a result, the inspectors reviewed this issue against the Group 2 questions to determine if the issue impacted one or more cornerstones. The inspectors determined that the "Initiating Event" cornerstone was affected since a reactor scram, an initiating event, occurred as a result of the improperly planned and performed maintenance activity. In addition, the inspectors determined that the issue affected the "Mitigation" cornerstone since the feedwater system is a mitigating system, and the MDRFP and TDRFPs were not immediately available for injection following the scram. As a result, the inspectors evaluated this issue utilizing the guidance provided by IMC 0609, "Significance Determination Process." During that review, the inspectors determined that since both the "Initiating Event" and "Mitigation" cornerstones were affected, that a Phase 2 Significance Determination Process (SDP) evaluation was required. This evaluation, completed under the oversight of the NRC Region III Senior Reactor Analyst (SRA), resulted in the classification of the issue, based on mitigating system availability, as being of low-risk (Green) significance. These results were shared and discussed with licensee probabilistic risk assessment personnel.

1R2 System Design Review and Results

a. Inspection Scope

The inspectors reviewed the potential design vulnerability which allowed a single blown fuse in the feedwater control system to cause a reactor scram.

b. Findings

The inspectors conducted interviews with plant personnel and reviewed drawings to confirm the design vulnerability that allowed an overcurrent condition affecting a single fuse to impact multiple instruments and equipment, resulting in a reactor scram.

The inspectors determined that a lack of individual instrument fuses (low level fuse coordination) in the feedwater control system was a design vulnerability which contributed to the sequence of events leading to the reactor scram. Specifically, the 24-volt power supply leads associated with the position transmitter for the MDRFP low flow feedwater valve, 2FW146, were shorted. However, because no fuse at the position transmitter existed, this resulted in an overcurrent condition at the output leads of 24-volt power supply 2C34-K611 which caused the 3-ampere, 120 volt-alternating current (VAC) supply fuse F7 to blow. The blown fuse caused a loss of the control signal to the MDRFP feedwater regulating valve, 2FW005. This power supply provided power to several other instruments, which were de-energized after the fuse blew, including the following:

- Main Steam Flow Indicators R6031A, R6031B, and R6031C
- 2A and 2B Reactor Recirculation Pump Low Level Trip
- Reactor Level 4 Low Alarm
- Feedwater Regulating Valve Manual/Automatic Transfer Station R610
- Feedwater Startup Controller R602
- 2B TDRFP Manual/Automatic Transfer Station R601B
- Valve Position Indication for Low Flow Feedwater Regulating Valve 2FW146

The functional result was a downshift of the reactor recirculation pumps, a loss of automatic reactor level control, a loss of manual level control for the 2B TDRFP, and an invalid reactor vessel low level alarm.

The inspectors identified that the loss of three main steam flow signals also resulted in a low power alarm on the Reactor Manual Control System. A review of the Rod Worth Minimizer log indicated that since the reactor scram occurred about 10 seconds after this alarm was received, it did not impact the event.

1R3 Motor-Driven Reactor Feedwater Pump Availability Review

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the initial unavailability of the motor-driven reactor feedwater pump.

b. Findings

The TDRFPs tripped on the reactor vessel high level signal as designed. When the TDRFPs tripped, the MDRFP started, but also tripped, as expected, on the high level signal. The MDRFP was successfully started once level decreased below the high level trip setpoint. However, the loss of power to MDRFP feedwater regulating valve manual/automatic transfer station R610, due to fuse F7 blowing, resulted in a loss of control signal to MDRFP feedwater regulating valve 2FW005. This valve failed closed and could not be automatically opened, resulting in no feedwater. This valve was manually opened about 19 minutes following the event.

The inspectors concluded that the initial unavailability of the MDRFP was a direct result of the initiating event.

1R4 RCIC Unstable Performance During Automatic Operation

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the unstable operation of the RCIC system and the corrective actions taken to address this problem prior to plant restart. The inspectors conducted interviews with licensee personnel and reviewed various work requests and other documentation.

b. Findings

The RCIC system was manually initiated after the reactor scram following the failure of the MDRFP and operated as expected in automatic for about 1 minute. Shortly thereafter, the flow signal began to oscillate. The oscillation was stable, undamped, and had a frequency of about one cycle per second. This signal propagated throughout the RCIC flow control system and caused a slight oscillation of the RCIC turbine control valve. After about 2 minutes, operators shifted the RCIC flow controller to manual because of questions about system performance while the flow oscillations were occurring. After shifting to manual, the oscillations ceased. The RCIC system was operated in manual until the MDRFP was restored to service, and then the RCIC system was secured.

After the event, the RCIC system injection check valves indicated open, instead of the expected shut position. Subsequently, the RCIC system was restarted and operated in accordance with Step E.2 of LOP-RI-03, “Reactor Core Isolation Cooling System Isolation and System Shutdown,” during the event recovery to assist in closing the RCIC injection check valves. The failure of the RCIC injection check valves to close was a known problem (reference Section 1R5 of this report). The operators reported that during this activity, the system operated in automatic and that no oscillations were observed.

To address the oscillations noted during RCIC system operation in automatic, IMD personnel, subsequent to the event and prior to unit restart, completed a system flow controller calibration under WR 990042708-01 and in accordance with LaSalle Instrument Surveillance (LIS) RI-202, “Unit 2 RCIC Pump Discharge Flow Calibration.”

During this activity, a square root converter was found to be out of tolerance. The RCIC system was subsequently tested satisfactorily and returned to service. Because this out of tolerance condition did not appear to be a likely cause of the oscillations observed, Condition Report L2001-02276 was generated to document this issue and Action Request 990142157 was generated to perform additional troubleshooting. This activity was in progress at the end of the inspection.

The inspectors concluded that based upon the information identified during the inspection, the RCIC system was injecting at or near rated flow in both automatic and manual, and was therefore available. The inspectors also concluded that the unstable behavior of the system following the scram unnecessarily required the crew's attention to address, which under different circumstances, may have adversely impacted event response.

1R5 RCIC Injection Line Check Valve Indication Anomalies

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the unexpected open indication of RCIC inboard and outboard injection check valves 2E51-F066 and 2E51-F065 following system shutdown and the actions taken to comply with Technical Specification requirements.

b. Findings

Following the restoration of reactor water level, the RCIC pump was secured. However, the inboard and outboard RCIC injection check valves, 2E51-F066 and 2E51-F065, unexpectedly indicated open instead of closed. In response to this issue, operators entered Technical Specification 3.6.3, "Primary Containment Isolation Valves," which required that with one or more primary containment isolation valves inoperable, maintain at least one isolation valve operable in each affected penetration that is open and within 4 hours either restore the inoperable valve to an operable status, or isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position, or isolate each affected penetration by the use of at least one closed manual valve or blind flange. Otherwise, be in at least hot shutdown within the next 12 hours and cold shutdown within the following 24 hours. However, as discussed below, Technical Specification 3.6.3 was not the proper Technical Specification for the operators to enter.

Subsequently, operators performed Step E.2 of LOP-RI-03, "Reactor Core Isolation Cooling System Isolation and System Shutdown," which restarted the RCIC system in an attempt to close the injection check valves. This problem, open indication of the injection check valves, had been observed during previous system operations and licensee personnel suspected the cause was due to a hydraulic locking effect. Following the performance of this activity, position indication for the outboard injection check valve, 2E51-F065, changed from open to closed. However, despite additional attempts to close 2E51-F066 via performance of LOP-RI-03, position indication for the inboard injection check valve, 2E51-F066, remained open.

To address the open indication associated with 2E51-F066, and to meet the requirements of Technical Specification 3.6.3, operators closed and de-energized 2E51-F013, the RCIC injection valve; and 2E51-F023, the Residual Heat Removal (RHR) reactor head spray discharge header isolation valve. In addition, Electrical Maintenance Department (EMD) personnel entered the drywell and performed activities prescribed by WR 990274402-01. During those activities, workers slightly rotated the 2E51-F066 position indicating rod, which resulted in a closed indication in the control room. Licensee personnel concluded that due to inherent design tolerances in the check valve, some "play" in the interface between the check valve shaft and the position indicating rod existed, which when removed, caused the closed indication limit switch to actuate. As a result, licensee personnel concluded that 2E51-F066 was already closed when the RCIC system was secured.

The inspectors reviewed the sequence of events described above, reviewed operator logs, conducted interviews with cognizant personnel, and identified the following issues:

- Technical Specification Requirements Review

The inspectors reviewed the LaSalle Technical Specifications and identified that Technical Specification 3.4.3.2, "Operational Leakage," had not been included in the operator logs as a Technical Specification which had been entered. The inspectors reviewed Technical Specification 3.4.3.2 and identified that Technical Specification 3.4.3.2.d and Table 3.4.3.2-1, "Reactor Coolant System Pressure Isolation Valves," required that with 2E51-F065 and 2E51-F066 open, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed valves, or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. The inspectors reviewed these requirements against those actions already taken and even though Technical Specification 3.4.3.2 was not entered as required, the entry into Technical Specification 3.6.3 resulted in meeting the requirements of Technical Specification 3.4.3.2. As a result, the inspectors concluded that no impact on safety resulted from the error. However, the inspectors also concluded that a lack of knowledge regarding the applicability of the Technical Specifications directly resulted in the failure to recognize that a Technical Specification entry was required. Licensee personnel generated Condition Report L2001-02207 to enter this issue into the corrective action program.

- Operator Workaround Concerns

As discussed above, licensee personnel utilized Procedure LOP-RI-03 to attempt to close the RCIC injection check valves which indicated open. The inspectors identified this as a potential operator workaround since it appeared that this condition may complicate the operation of plant equipment and was compensated for by operator action. The inspectors identified that rotation by hand of the position indicating rod associated with 2E51-F066 may also be an operator workaround. The inspectors discussed both of these issues with licensee personnel who indicated that both conditions were known historical problems which had not been evaluated as potential operator workarounds. At the end of the inspection, licensee personnel generated Condition Report L2001-02148 to process both of these conditions as potential operator workarounds.

1R6 Event Risk Review Results

a. Inspection Scope

The initial risk assessment performed by the Region III SRA determined that the overall conditional core damage probability (CCDP) following the event was about 4E-6. This preliminary bounding calculation assumed a loss of all feedwater (a loss of both TDRFPs and the MDRFP). Discussions with licensee management shortly after the event indicated that licensee risk assessment personnel had performed a similar evaluation and concluded that the overall risk was on the order of 1E-8, a value substantially lower than that determined by the Region III SRA. As a result, a Region III SRA took part in the special inspection to understand the differences between the two risk assessments.

b. Findings

Background - NRC's Risk Assessment Methodology

The risk significance of an event is characterized by the probability that the core could have been damaged at the moment of the event given actual conditions. Conversely, the NRC's Significance Determination Process (SDP) estimates the increase in Core Damage Frequency (CDF) for the spectrum of all postulated initiating events over a period of time during which known equipment or functional degradation existed. Although the SDP may provide some useful risk insights for event response or followup, it was not designed or intended to be used for this purpose and the NRC does not utilize the SDP for event significance evaluations.

The significance of operational power reactor events are evaluated for risk by determining the Conditional Core Damage Probability (CCDP) which reflects the loss of defense-in-depth due to the event, regardless of the cause. The CCDP accounts for actual plant configuration, including equipment rendered unavailable due to maintenance, testing, or other reasons. Although CCDP represents a fundamentally different concept for events than for degraded conditions that do not initiate an event, the same guidelines may be applied to each in assisting management in its risk-informed decision-making. Inspection Manual Chapter 0609, "Significance Determination Process," was designed to evaluate the incremental increase in CDF (ICDF) due to a performance deficiency; however, it does not address CCDP determination for event assessments.

Licensee Risk Assessment Review

The inspectors identified that the licensee's initial risk assessment was requested by licensee management to review the Incremental Conditional Core Damage Probability (ICCDP) utilizing techniques similar to that applied in the NRC's SDP, and was not intended to be utilized as a formal event assessment analyzing the overall risk as a result of the reactor scram. It appeared that licensee management personnel were interested in evaluating the event using techniques similar to the NRC's SDP and were unaware that the NRC did not rely upon the SDP process to assess the risk significance of actual events. As a result, licensee personnel generated Condition Report

L2001-02242 to identify that licensee personnel incorrectly applied the SDP methodology to perform the risk assessment of the event, instead of the event followup methodology to calculate event-specific CCDP.

Following discussions with the Region III SRA, licensee personnel re-performed a risk assessment of the event. The quantitative analysis performed by the licensee utilizing assumptions similar to those used by the Region III SRA resulted in a CCDP which correlated well with the NRC's preliminary analysis.

Final Event Risk Assessment

The inspectors reviewed actual equipment conditions during the event to determine the probability of recovering mitigating equipment challenged during the event and to refine the initial event risk assessment. The mitigating equipment potentially impacted included the TDRFPs, the MDRFP, and the RCIC system. The following conclusions regarding the availability of these systems for accident mitigation were reached:

TDRFPs — The inspectors concluded that the "A" TDRFP was recoverable following the reactor scram. However, the "B" TDRFP was assumed to be unavailable since no procedures existed to direct operators to restore the pump to service. This was a conservative assumption since operators may have been able to restart the pump solely based on their level of training.

MDRFP — The MDRFP automatically started following the trip of the second TDRFP; however, the pump receives a trip signal due to the high reactor vessel level condition. Following the reactor scram, operators manually started the pump, but were initially unable to inject water into the reactor vessel due to the inability to open the feedwater regulating valve, due to a loss of power to the controller as a result of the blown fuse. Operators subsequently manually opened the valve about 19 minutes after the scram.

RCIC — The RCIC pump experienced oscillating flow indications in the control room. Operators were concerned with the operation of the RCIC system, and placed the system in manual control. The inspectors concluded that operator intervention was not required and that the RCIC system, although operating with indicated discharge flow oscillations, was capable of performing its intended function without operator intervention.

In light of the revised mitigating equipment availability, the Region III SRA re-performed the risk assessment utilizing the NRC's Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE) computer program with the LaSalle Simplified Plant Analysis Risk (SPAR) Model 3i. The calculated CCDP was 1.3E-6. The licensee independently re-performed a similar risk assessment using their models and calculated a revised CCDP of 1.5E-6. Licensee personnel also concluded that this calculation was conservative, since recent model refinements had not been included in the calculation.

The inspectors concluded that based upon the revised risk assessment, the event was of low risk-significance.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. M. Schiavoni and other members of licensee management on April 13, 2001. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Exelon

D. Bost, Site Engineering Manager
T. Gierich, Maintenance Manager
R. Gilbert, Work Control Manager
F. Gogliotti, Design Engineering Supervisor
J. Henry, Shift Operations Superintendent
G. Kaegi, Site Training Manager
C. Pardee, Site Vice President
J. Pollock, System Engineering Manager
W. Riffer, Regulatory Assurance Manager
M. Schiavoni, Station Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Closed

None

Discussed

None

List of Documents Reviewed

NRC Procedures

NRC Inspection Procedure 93812, “Special Inspection,” dated March 6, 2001
NRC Inspection Procedure 71153, “Event Followup,” dated March 6, 2001
NRC Management Directive 8.3, “NRC Incident Investigative Procedures”
Inspection Manual Chapter 0609, “Significance Determination Process”
Inspection Manual Chapter 0610*, “Power Reactor Inspection Reports”

Condition Reports

L2001-02137	Unit 2 Reactor Scram
L2001-02148	2E51-F065 and 2E51-F066 Failed to Indicate Closed After RCIC was Secured
L2001-02207	Inadvertent Technical Specification Actions Entered
L2001-02221	Excessive Flow Oscillations During Forced Outage L2F31
L2001-02276	Unit 2 RCIC Oscillations During Operation Following Scram on April 6, 2001

Drawings

1E-2-4205AS Schematic Diagram Feedwater Control System (B33) Part 17
1E-2-4205AV Schematic Diagram Feedwater Control System (B33) Part 20
1E-2-4208AJ Schematic Diagram Feedwater Control System (C34) Part 9
1E-2-4208AK Schematic Diagram Feedwater Control System (C34) Part 10
1E-2-4208AL Schematic Diagram Feedwater Control System (C34) Part 11
1E-2-4208AM Schematic Diagram Feedwater Control System (C34) Part 12
1E-2-4208AN Schematic Diagram Feedwater Control System (C34) Part 13
1E-2-4208AP Schematic Diagram Feedwater Control System (C34) Part 14
1E-2-4208AQ Schematic Diagram Feedwater Control System (C34) Part 15
1E-2-4208AR Schematic Diagram Feedwater Control System (C34) Part 16
1E-2-4208AS Schematic Diagram Feedwater Control System (C34) Part 17
1E-2-4208AU Schematic Diagram Feedwater Control System (C34) Part 19
1E-2-4208BJ Schematic Diagram - Low Flow Valve Feedwater Control System
M-118, Sheet 1, Feedwater System Piping and Instrumentation Diagram

List of Documents Reviewed

Licensee Procedures

OP-AA-101-303, “Operator Work-Around Program,” Revision 0
LEP-GM-181, “Testable Check Valve Limit Switch Adjustment,” Revision 3, dated March 17, 1999
LIS-RI-202, “Unit 2 RCIC Pump Discharge Flow Calibration,” Revision 5, dated July 31, 2000
LOP-FW-04, “Startup of Turbine Driven Reactor Feedwater Pump (TDRFP),” Revision 32, dated February 7, 2001
LOP-RI-03, “Reactor Core Isolation Cooling System Isolation and System Shutdown,” Revision 13, dated September 11, 2000
WC-AA-103, “On-Line Maintenance,” Revision 3
WC-AA-104, “Review and Screening for High Production Risk Activities and Work Authorization,” Revision 1
LaSalle Emergency Operating Procedure LGA-01, “RPV [Reactor Pressure Vessel] Control”

Work Requests

Work Request 990265385-01, “Controller Signal Versus Valve Position Disagree”
Work Request 990141379-01, “Valve Will Not Close After RCIC Secured”
Work Request 990274402-01, “Adjust Limits, Replace Solenoid if Required”
Work Request 990042708-01, “LMT-02-LIS-RI-202 Unit 2 RCIC Pump Flow Indication Calibration”
Work Request 950072484-01, “Unit 2 RCIC Pump Discharge Flow Indication Calibration”
Work Request 990035955-01, “RCIC Pump Discharge Flow Indication Calibration”
Work Request 990042708-01, “RCIC Pump Discharge Flow Indication Calibration”

Other

Event Notification 37895, dated April 6, 2001
LaSalle Event Response Team Charter, Condition Report L2001-02137, dated April 6, 2001
Prompt Investigation Report L2001-02137, “Unit 2 Automatic Scram,” dated April 6, 2001
Preliminary Investigation Report, “Failed Cooper/Bussman Fuse”
LaSalle Unit 2 Operator Logs
UFSAR/FPR Change Request Form LU2000-138
Out-of-Service 990031210, “RCIC Injection Inboard Testable Check,” Checklists 1 and 2
Hathaway Alarm Typer Data for April 6, 2001
Transient Acquisition and Data System (TADS) Traces of RCIC Operation
LaSalle Technical Specification 3.6.3, “Primary Containment Isolation Valves”
LaSalle Technical Specification 3.4.3.2, “Operational Leakage”
Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE)
LaSalle Simplified Plant Analysis Risk (SPAR) Model 3i