June 17, 2005

Mr. Fred Dacimo
Site Vice President
Entergy Nuclear Operations, Inc.
Indian Point Nuclear Generating Station
295 Broadway, Suite 1
Post Office Box 249
Buchanan, NY 10511-0249

SUBJECT: INDIAN POINT 2 - NRC INSPECTION REPORT 05000247/2005006 PRELIMINARY WHITE FINDING

Dear Mr. Dacimo:

On March 4, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed onsite inspection activities associated with an engineering team inspection at the Indian Point 2 Nuclear Power Plant. Following completion of the onsite inspection activities, the NRC team continued inspecting an issue related to nitrogen gas migration and accumulation in the safety injection system. This portion of the inspection was completed on April 27, 2005, following an onsite discussion with your technical staff on April 18, 2005. The enclosed report documents the inspection findings, which were discussed with Mr. C. Schwarz and other members of your staff via telephone during an exit meeting on May 18, 2005.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your operating license. The inspection involved field walkdowns, examination of selected procedures, calculations and records, and interviews with station personnel.

This report documents one finding that appears to have low to moderate safety significance. As described in Section 4OA2.1 of the attached report, this finding involved inadequate evaluation and corrective actions for a degraded condition. Specifically, water from the No. 24 safety injection accumulator leaked past several closed valves, allowing water containing absorbed nitrogen to reach other portions of the emergency core cooling system (including the common suction supply piping for the safety injection pumps and the No. 23 safety injection pump casing). As the water moved from a higher to lower system pressure, the nitrogen gas was released from the water, thereby challenging the performance of the safety injection pumps. While this issue did present a potential safety concern upon discovery, appropriate corrective and compensatory measures were implemented.

This finding was assessed based on information and documents reviewed at the time of the inspection, as well as standard industry acceptance criteria and practices regarding gas flow dynamics and void fraction transport, using the applicable Significance Determination Process. The finding was assessed as a potentially safety significant finding that was preliminarily determined to be White (i.e., a finding with some increased importance to safety, which may require additional NRC inspection). The basis for the NRC's preliminary significance determination is described in the enclosed report.

In conjunction with this preliminary White finding, the NRC characterized the associated performance deficiency as an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI (Corrective Action). The preliminary White characterization was due, in part, to the uncertainties in the outcome of the analysis regarding the ability of the safety injection system to perform its safety function. This apparent violation is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy). The current Enforcement Policy is included on the NRC's Website at http://www.nrc.gov/what-we-do/regulatory/enforcement.html. No Notice of Violation is being issued for this inspection finding at this time because the NRC has not made a final determination in this matter. In addition, please be advised that the characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

We believe that we have sufficient information to make our final risk determination for the performance issue regarding the inadequate evaluation and corrective action associated with the gas accumulation in the safety injection system. However, before the NRC makes a final decision on this matter, we are providing you an opportunity to either submit a written response, or to request a Regulatory Conference where you would be able to provide your perspectives on the significance of the finding and the bases for your position. If you choose to request a Regulatory Conference, it should be held within 30 days of the receipt of this letter, and we encourage you to submit your evaluation and any differences with the NRC evaluation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the Regulatory Conference. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Mr. L. Doerflein at (610) 337-5378 within 10 business days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

The enclosed report also documents one NRC-identified finding of very low safety significance (Green). This finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator Region I; Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at Indian Point 2.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) 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 by Richard V. Crlenjak Acting For/

A. Randolph Blough, Director
Division of Reactor Safety

Docket No. 50-247
License No. DPR-26

Enclosure: Inspection Report 05000247/2005006
w/Attachment: Supplemental Information

cc w/encl:
G. J. Taylor, Chief Executive Officer, Entergy Operations, Inc.
M. R. Kansler, President - Entergy Nuclear Operations, Inc.
J. T. Herron, Senior Vice President and Chief Operating Officer
P. Rubin, General Manager - Plant Operations
O. Limpias, Vice President, Engineering
C. Schwarz, Vice President, Operations Support
J. McCann, Director, Licensing
C. D. Faison, Manager, Licensing, Entergy Nuclear Operations, Inc.
P. Conroy, Manager, Licensing, Entergy Nuclear Operations, Inc.
M. Colomb, Director of Oversight, Entergy Nuclear Operations, Inc.
J. Comiotes, Director, Nuclear Safety Assurance
J. M. Fulton, Assistant General Counsel, Entergy Nuclear Operations, Inc.
P. R. Smith, President, New York State Energy, Research and Development Authority
J. Spath, Program Director, New York State Energy Research and Development Authority
P. Eddy, Electric Division, New York State Department of Public Service
C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
D. O'Neill, Mayor, Village of Buchanan
J. G. Testa, Mayor, City of Peekskill
R. Albanese, Executive Chair, Four County Nuclear Safety Committee
S. Lousteau, Treasury Department, Entergy Services, Inc.
Chairman, Standing Committee on Energy, NYS Assembly
Chairman, Standing Committee on Environmental Conservation, NYS Assembly
Chairman, Committee on Corporations, Authorities, and Commissions
M. Slobodien, Director, Emergency Planning
B. Brandenburg, Assistant General Counsel
P. Rubin, Manager of Planning, Scheduling & Outage Services
Assemblywoman Sandra Galef, NYS Assembly
County Clerk, Westchester County Legislature
A. Spano, Westchester County Executive
R. Bondi, Putnam County Executive
C. Vanderhoef, Rockland County Executive

E. A. Diana, Orange County Executive
T. Judson, Central NY Citizens Awareness Network
M. Elie, Citizens Awareness Network
D. Lochbaum, Nuclear Safety Engineer, Union of Concerned Scientists
Public Citizen's Critical Mass Energy Project
M. Mariotte, Nuclear Information & Resources Service
F. Zalcman, Pace Law School, Energy Project
L. Puglisi, Supervisor, Town of Cortlandt
Congresswoman Sue W. Kelly
Congresswoman Nita Lowey
Senator Hillary Rodham Clinton
Senator Charles Schumer
J. Riccio, Greenpeace
A. Matthiessen, Executive Director, Riverkeeper, Inc.
M. Kapolwitz, Chairman of County Environment & Health Committee
A. Reynolds, Environmental Advocates
M. Jacobs, Director, Longview School
D. Katz, Executive Director, Citizens Awareness Network
P. Gunter, Nuclear Information & Resource Service
P. Leventhal, The Nuclear Control Institute
K. Coplan, Pace Environmental Litigation Clinic
W. DiProfio, PWR SRC Consultant
D. C. Poole, PWR SRC Consultant
W. Russell, PWR SRC Consultant
W. Little, Associate Attorney, NYSDEC
R. Christman, Supt. Operations Training
L. Cortopassi, Manager Training and Development
S. Glenn, INPO

Distribution w/encl:
S. Collins, RA
A. Blough, DRS
R. Crlenjak, DRS
L. Doerflein, DRS
S. Lee, RI OEDO
R. Laufer, NRR
J. Boska, PM, NRR
P. Tam, PM, NRR (Backup)
P. Milano, PM, NRR (Backup)
B. McDermott, DRP
D. Jackson, DRP
C. Long, DRP
P. Habighorst, DRP, Senior Resident Inspector - Indian Point 2
M. Cox, DRP, Resident Inspector - Indian Point 2
R. Martin, DRP, Resident OA
Region I Docket Room (w/concurrences)
ROPreports@nrc.gov

SISP Review Complete: ***LTD***

DOCUMENT NAME: E:\Filenet\ML051680119.wpd
After declaring this document "An Official Agency Record" it **will** be released to the Public.
To receive a copy of this document, indicate in the box: "**C**" = Copy without attachment/enclosure "**E**" = Copy with attachment/enclosure "**N**" = No copy

OFFICE	RI/DRS	RI/DRS	RI/DRP	RI/ORA
NAME	SMPindale/***SMP***	WLSchmidt/***WLS***	BMcDermott/***DEJ for***	RUrban/***RJU****
DATE	6/13/05	6/14/05	6/14/05	6/13/05

OFFICE	RI/DRS	RI/DRS		
NAME	LTDoerflein/***LTD***	ABlough/***RVC for***		
DATE	6/16/05	6/16/05		

OFFICIAL RECORD COPY

***Cover Letter Only**

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-247
License No.	DPR-26
Report No.	05000247/2005006
Licensee:	Entergy Nuclear Operations, Inc.
Facility:	Indian Point 2 Nuclear Power Plant
Location:	Buchanan, New York 10511
Dates:	February 14 - 18, 2005 (onsite); February 28 - March 4, 2005 (onsite); and March 7 - April 27, 2005 (in-office)
Inspectors:	S. Pindale, Senior Reactor Inspector (Team Leader) F. Arner, Senior Reactor Inspector J. Bobiak, Reactor Inspector C. Colantoni, Reactor Inspector A. Patel, Project Inspector J. Richmond, Reactor Inspector A. Rosebrook, Reactor Inspector T. Sicola, Reactor Inspector M. Cox, Resident Inspector (part-time member) W. Lyon, Senior Reactor Systems Engineer (part-time member)
Approved By:	Lawrence T. Doerflein, Chief Engineering Branch 2 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000247/2005006; 02/14/05 - 02/18/05 (onsite), 02/28/05 - 03/04/05 (onsite), 03/07/05 - 04/27/05 (in-office); Indian Point 2 Nuclear Power Plant; Safety System Design and Performance Capability.

The inspection was conducted by eight region-based inspectors, one resident inspector, and one engineer from the Office of Nuclear Reactor Regulation. One preliminary White finding and apparent violation were identified; and one finding of very low safety significance (Green) involving a non-cited violation (NCV) was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or may be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Cornerstone: Mitigating Systems

- Preliminary White. An apparent violation of 10 CFR 50, Appendix B, Criterion XVI (Corrective Action) and station procedures were identified associated with the failure to evaluate and correct a condition adverse to quality. Specifically, the condition adverse to quality involved the leakage of water from the No. 24 safety injection accumulator past several closed valves, allowing water containing absorbed nitrogen to reach other portions of the safety injection emergency core cooling system (including the common suction supply piping for the safety injection pumps and the 23 safety injection pump casing). As the water moved from a higher to lower system pressure, the nitrogen gas was released from the water, thereby challenging the performance of the safety injection pumps. In addition, Entergy's initial evaluation of this condition did not appropriately consider available industry operating experience relative to gas migration into emergency core cooling system piping.

  This issue is greater than minor because it is associated with the Equipment Performance attribute of the Mitigation Systems cornerstone and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. The Significance Determination Process (SDP) Phase 1, Phase 2, and Phase 3 were used to determine that this issue represented a finding with preliminarily low to moderate safety significance. The analysis used the NRC's best functionality estimates for the three safety injection pumps over a 17-day period when it was judged that adverse gas accumulation conditions existed. Specifically, the 23 safety injection pump was not functional due to the pump casing being filled with gas. The team concluded that the 21 and 22 pumps, given the accumulated gas in the pump suction piping, would not have functioned 75% of the time (assigned a 75% failure probability) for high flowrate and low discharge pressure conditions in response to a medium break loss of coolant accident; and 25% of the time for low flowrate and high discharge pressure conditions in response to other initiating events. The Phase 1 screening identified that a Phase 2 analysis was needed because the 23 safety injection pump train was not functional for longer than the technical specification allowed outage time of 72 hours. Given the uncertainty in the Phase 2 analysis, a Phase 3 analysis was necessary to improve the accuracy of the result. The Phase 3 analysis for internal and external initiating events, using the above assumptions and licensee risk information, identified an increase in core damage frequency of approximately 1 in 900,000 years of operation (low E-6 per year range); and an increase in large early release frequency of approximately 1 in 3,000,000 years of operation (low E-7 per year range). (Section 4OA2.1)

- Green. The team identified a finding where Entergy had used non-conservative post-accident recirculation pump motor loading conditions in an analysis that determined overload trip settings for the associated 480 Volt circuit breakers. This finding was determined to be a violation of 10 CFR 50, Appendix B, Criterion III (Design Control).

  This finding is greater than minor because it is associated with the Equipment Performance attribute of the Mitigation Systems cornerstone and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. This finding is of very low safety significance because it is a design deficiency that did not result in a loss of function. (Section 1R21)

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R21 Safety System Design and Performance Capability (IP 71111.21)

a. Inspection Scope

The team reviewed the design and performance capability of several systems, components and functions, including the low pressure and high pressure recirculation portions of the emergency core cooling system; and portions of the main steam system (main steam isolation valves, atmospheric dump valves, and safety relief valves). The inspection included a sample of supporting components for the selected systems. The team reviewed the design basis documents, the Updated Final Safety Analysis Report (UFSAR), Technical Specifications, design changes and calculations, and other documents to ensure that the systems could be relied upon to meet their functional requirements. In addition, the team used risk insights relative to the selected systems to focus inspection activities on components and procedures that would mitigate the effects of postulated events.

Regarding the low pressure and high pressure recirculation emergency core cooling functions, the team focused on portions of the recirculation, residual heat removal (RHR) and safety injection (SI) subsystems. The team reviewed the system interactions associated these systems, including where the design specified a transfer to the SI system to support high pressure recirculation. Component performance (including selected pumps, valves, heat exchangers, orifices, and instrumentation) was evaluated with respect to design requirements during normal plant operation and postulated accident scenarios. In addition, the team reviewed the applicable system procedures that controlled alignment and operational activities during normal evolutions, and abnormal and emergency scenarios. The team reviewed operations and test procedures and the operator training material to evaluate the consistency between assumptions made in the system design and expected system and operator response.

For the selected main steam system components, the team similarly reviewed specific component performance with respect to design requirements during normal plant operation and postulated accident scenarios. The team also reviewed system procedures that controlled alignment and operational activities during normal evolutions, and abnormal and emergency scenarios. Operating and test procedures and the training lesson plans were reviewed by the team to evaluate the consistency between the assumptions made in the system design and the expected system response.

The team interviewed various plant personnel responsible for system status, licensing basis controls, and the implementation of modifications to verify the adequacy of programs and procedures that addressed the system design basis considerations and work control practices. Several design change packages were reviewed along with the supporting calculations to validate that the design inputs to the system modifications were accurate and that the analytical results and conclusions reflected acceptable system performance.

The team reviewed test procedures and completed test results, including in-service testing, for the selected systems. Design requirements for the periodic testing of valves that are required to change position during a transfer to the recirculation phase of a postulated scenario were discussed with operations and engineering personnel to ensure proper understanding of the constraints on full system availability and transient (e.g., water hammer) considerations.

The team performed a review of selected parameters (e.g., room cooling, system flowrates, valve response times, relief valve actuation setpoints) affecting design inputs and systems and components supporting the selected systems to verify that the system configuration was consistent with the design basis.

A walkdown of the control room was conducted to verify specific plant controls. Discussions with operations personnel were conducted to confirm that proper emphasis was placed upon system/component design and accident response assumptions in the training scenarios and emergency procedures. Design basis documents for the selected systems were also reviewed to check for proper integration into operations and surveillance procedures and training plans. The team also reviewed the capability of the operators to perform certain actions directed by abnormal and emergency procedures, given expected plant conditions and the availability of time that is assumed for postulated accidents.

The team performed field walkdowns of the accessible portions of the selected systems to assess the material condition and verify that the installed configuration was consistent with design drawings, operating procedures, and other design information. The team assessed the adequacy of environmental protection measures to ensure that temperature sensitive components, such as motor-operated valves, would perform their safety functions. The team reviewed the operator work-around list, system engineer tracking/trending data, health reports, temporary modifications, work order backlog, and corrective action database to assess the overall health of the systems.

With respect to the electrical portions of the systems, the team reviewed control wiring diagrams associated with RHR, recirculation and SI components to verify that their operation and automatic initiation, when applicable, were in conformance with the design basis documents and UFSAR descriptions. The team verified that the control of valves critical to the proper operation of the systems was as specified in the design basis documents. Additionally, the team reviewed the refueling water storage water (RWST) and recirculation and containment level setpoint calculations to ensure that an adequate water volume was available to the pumps and did not impair their ability to perform their safety function. The team reviewed alternating current and direct current power distribution single line diagrams and the protective component coordination studies to ensure that a fault or single failure of an electrical component or source did not impair the ability of the systems to perform their specified safety function. The team also confirmed that sufficient instrumentation had been provided to initiate automatic functions and to monitor the operation of the systems during and following a plant abnormal event.

The team reviewed the load flow analysis and the emergency diesel generator (EDG) loading calculation to verify that the loads addressed had been correctly identified in the calculation and to assure that the EDGs were capable of meeting the load requirements under worst-case conditions. Through a review of the voltage drop calculation, the team also verified that adequate voltage was provided to the safety-related loads during normal, abnormal and emergency loading conditions. The team reviewed the environmental qualification of motors and valves within the scope of the inspection to verify they would be capable of performing their safety function following an accident.

The team utilized risk achievement worth information along with the NRC's Significance Determination Process (SDP) Phase 2 worksheets to select components to review in-depth. Some of the components selected for detailed review included the SI suction valve (from the refueling water storage tank), the parallel suction valves from the low pressure recirculation systems, and the SI pump minimum flow valves. System operability reviews were selected for review to ensure the technical basis for operability conclusions were supported and valid. Additionally, maintenance procedures, including preventive maintenance work instructions, were reviewed to ensure consistency with vendor technical manual requirements.

b. Findings

480 Volt DB Circuit Breaker Setting For Recirculation Pump Motors

Introduction. The team identified a finding of very low safety significance (Green) associated with the use of non-conservative post-accident recirculation pump motor loading conditions in an analysis for determining overload trip settings for the associated 480 Volt type DB circuit breakers. The issue was determined to be a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III (Design Control).

Description. The team reviewed calculation 60817-6, "480 Volt DB Circuit Breaker Setting for the 350 HP Recirculation Pump Motors," in order to verify the protective circuit breaker settings were adequate. The purpose of this calculation was to provide a protective circuit breaker setting for an amptector (an overcurrent trip device) to preclude tripping of the associated recirculation pump motor during maximum credible loading at the degraded voltage setpoint. This method provided for the worst case design condition, while ensuring adequate protection against motor overload.

The analysis provided two criteria that must be satisfied. The first was that the amptector long time characteristic must not exceed the most limiting worst case current conditions. The second criterion was that the circuit breaker's lowest limit setting would be less than 140% of the motor's full load amperage. The team determined that the worst case brake horsepower used in determining the most limiting current conditions was non-conservative in that it based the worst case brake horsepower on a design flowrate condition of 3000 gpm. The team recognized that in the 1998 - 1999 timeframe, emergency operating procedures had been revised such that operators no longer controlled flowrate conditions to 3000 gpm. Instead, system resistance values were used in vendor calculations to determine the maximum possible flowrate conditions. Accordingly, procedure ES 1.3, "Transfer to Cold Leg Recirculation," required one recirculation pump in operation with a flowpath through two residual heat removal (RHR) system heat exchangers. A vendor analysis determined that this arrangement could result in flowrates in excess of 4000 gpm. Emergency diesel generator (EDG) loading calculations had utilized a nominal 4500 gpm flowrate as a design input in this condition.

The team utilized this higher flowrate and determined the new brake horsepower requirements. With the system bus voltage assumed to be at the degraded voltage setpoint, the team determined that there was a potential for the amptector long time trip characteristic to inadvertently open the circuit breaker and trip the associated recirculation pump motor under these conditions.

In response to the team's concerns, Entergy entered this issue into their corrective action program as condition report CR-IP2-2005-00908. The engineering evaluation noted that the 480 Volt buses are provided with degraded voltage protection, and safety-related loads should be able to operate satisfactorily at all voltages above the degraded relay setpoint. This is a design basis assumption noted in Section 8.1.2.1 of the UFSAR. Entergy determined in their operability evaluation that the projected pump and motor loading under degraded offsite power conditions could result in motor current being within the trip range of the 480 Volt feeder breakers associated with these pumps. The concern for breaker tripping only occurs for accidents with degraded offsite power conditions under design basis considerations. Specifically, these conditions are maximum electrical bus loading, minimum expected 138 kV grid voltage, and maximum flow/loading for the recirculation pumps.

Entergy performed a reasonable expectation of operability analysis and determined that maximum loading during the recirculation phase of an accident will be less than that of automatic loading. This lower load condition would provide for higher voltages and additional margin, such that the pump motor current would be less than the breaker trip values. Additionally, operators would be expected to respond to the low voltage conditions by raising grid voltage back to voltage schedule requirements, which would also provide margin and result in higher bus voltages during the recirculation phase of an accident. The team reviewed Entergy's preliminary evaluation and determined the assumptions and conclusions were reasonable. The operability review stated that the design basis for the amptector settings would be reviewed and appropriate actions taken. The team also noted this concern did not apply to recirculation when the safety-related buses are powered from the EDGs because voltage regulation would maintain adequate bus and motor voltages such that inadvertent tripping of the breakers would not occur.

Analysis. The team determined this to be a performance deficiency because Entergy's recirculation pump motor circuit breaker settings were based on a non-conservative recirculation pump flowrate design input. Specifically, the calculation of record did not ensure the operability of the recirculation pumps for all conditions where bus voltage remained above the allowable minimum Technical Specification values for the degraded voltage relay dropout settings. The finding is more than minor because it is associated with the Equipment Performance attribute of the Mitigation Systems cornerstone and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. The issue screened as very low safety significance (Green) in Phase 1 of the SDP because it is a design deficiency that did not result in a loss of function.

Enforcement. 10 CFR 50, Appendix B, Criterion III (Design Control), requires that measures be established to assure that applicable regulatory requirements and the design basis for structures, systems and components are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, Entergy used incorrect and non-conservative loading values in calculations to ensure that equipment would remain operable under degraded voltage conditions. Since this finding is of very low safety significance (Green) and has been entered into Entergy's corrective action program (CR-IP2-2005-00908), this finding is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000247/2005006-01, Non-Conservative Post-Accident Recirculation Pump Motor Loading Conditions Used to Determine Overload Trip Settings for 480 Volt Type DB Circuit Breakers)**

4OA2 Identification and Resolution of Problems (IP 71152)

1. Annual Sample Review

Nitrogen Gas Migration and Accumulation in the Safety Injection System

a. Inspection Scope

On January 26, 2005, while investigating continuing level and pressure losses in the No. 24 SI accumulator, Entergy personnel discovered that nitrogen gas had accumulated in portions of the safety injection (SI) system. This discovery was made through ultrasonic test (UT) examination and venting operations.

The team selected this issue as a Problem Identification and Resolution (PI&R) sample in order to assess Entergy's response to this condition with an immediate emphasis on current operability of the SI system. The team initially focused its review on Entergy's evaluation and corrective actions following the discovery of the degraded condition. The team reviewed the sequence of events leading up to the discovery of gas, including a review of Entergy's root cause evaluation. The team independently reviewed the details by conducting walkdowns of the system, interviewing station personnel, and reviewing related documents. The team's independent review was performed in order to ensure that the cause was understood and the planned and completed corrective actions were adequate to prevent recurrent or similar problems. The team reviewed Entergy's plan for venting operations and UT examination results of associated piping. Entergy's plan was an ongoing corrective action plan (February 2005), which Entergy had developed to ensure that gas no longer was a threat to the functionality of the system. The team also evaluated the performance of Entergy's organization with respect to its overall response to the degraded condition, from initial identification within the corrective action system through the prioritization, evaluation and followup actions.

Finally, the team gathered facts in order to evaluate the safety significance of the issue as it had existed prior to the January 26, 2005, discovery of nitrogen gas in portions of the SI system. The team's review was completed on April 27, 2005, and included a review of Entergy's evaluation of the impact of the gas to the SI system. The team reviewed calculations that Entergy developed to determine the amount of gas that was originally found in the common suction piping to all three SI pumps. The team assessed the key factors and assumptions associated with Entergy's determination of the amount of gas found; and collected and analyzed data necessary to support a preliminary risk analysis. The team used engineering judgment and various available technical documents pertaining to the impact of gas on centrifugal pump operation to independently determine an estimated overall risk significance of the condition.

b. Findings

Introduction. The team identified an apparent violation of 10 CFR 50, Appendix B, Criterion XVI (Corrective Action). A Significance Determination Process Phase 3 risk analysis determined that the failure to adequately address the accumulation of gas within the common suction SI piping and the No. 23 SI pump casing resulted in a finding of low to moderate safety significance.

Description. The team reviewed the details of system design and operation, Entergy's response to the condition adverse to quality, the impact and risk of the condition on the SI system, and Entergy's corrective actions.

Background. The ECCS contains pumps and pressurized tanks of water, called accumulators, to provide water to the reactor coolant system (RCS) and to ensure core cooling in the event of a loss of coolant accident (LOCA). The RCS typically operates at a pressure of about 2235 psig, and the accumulators are maintained at approximately 650 psig whereas most of the remainder of the ECCS is not pressurized. The SI system, which is part of the ECCS, pumps water to the RCS in both the injection and recirculation phases of an LOCA response. Check valves are provided as part of the system design to prevent high pressure water contained in either the RCS or accumulators from entering connected systems that are typically maintained at a lower pressure.

Accumulator pressure is maintained by a volume of high pressure nitrogen (650 psig) in approximately the top half of the accumulator tank. Some of this nitrogen will be absorbed into the accumulator water. Hence, leakage of water from this source into the lower pressure components of the ECCS can release gas as the nitrogen would come out of solution at the lower pressure. There would be an immediate surge as the pressure is reduced, followed by a gradual release of gas as the absorbed gas volume approaches equilibrium with the lower pressure. Gas released into the piping and pumps of the ECCS can result in: (1) water hammer due to compression of the gas when starting ECCS pumps, and (2) loss of ECCS pump capability because of the impact on pump performance and the potential for gas binding where the impeller is no longer able to effectively contact the fluid to function correctly. Centrifugal pumps are designed so that their pump casings are completely filled with liquid during pump operation.

Upon initial startup, the SI pumps take suction from a common 8-inch header that is supplied by the refueling water storage tank (RWST). The 21 SI pump provides water to one discharge line that penetrates containment and then to the RCS. The 23 SI pump similarly provides water to a second discharge line, and then through containment to the RCS. The 22 SI pump provides water to a header and, if the 21 or the 23 SI pump fails to start, the water from the 22 SI pump will flow into the line that would have been charged by the failed pump. Availability of two of the three SI pumps is necessary to meet functional licensing basis requirements, and operability of three SI pumps is required to meet the single failure requirement that is part of the IP-2 licensing basis.

The SI pump suction side flow path from the RWST is as follows. Water from the RWST flows into the common 8-inch line at centerline elevation of 71'0". Water from this 8-inch line enters a 6-inch line via a side-entering tee, continues horizontally, and then flows vertically downward to elevation 61'8.5" where it enters the 23 SI pump. Continuing in the direction of the common 8-inch suction header flow, water enters another 6-inch line via a side-entering tee, continues horizontally for a short distance, flows vertically downward to elevation 61'8.5" where it passes through two valves and connects to the 22 SI pump. Again continuing in the direction of the common 8-inch suction header flow, the 8-inch line is reduced to a 6-inch line by a concentric reducer. Water in this section of the line continues along a horizontal path, and then flows vertically downward to elevation 61'8.5" where it enters the 21 SI pump.

Based on reviews of condition reports (CR), interviews of Entergy staff, and evaluation of data and gathered information, the team noted that during the startup and return to power following the 2R16 refueling outage (Fall 2004), the No. 24 SI accumulator had to be re-pressurized and refilled frequently (about every 12 - 48 hours) to maintain the technical specification accumulator pressure and level requirements. The team noted that while the degraded accumulator condition had been identified on November 21, 2004, and entered into the corrective action program (CR-IP2-2004-06364), the organization failed to recognize the potential impact that the No. 24 accumulator leakage could have relative to gas intrusion into the lower pressure safety injection system.

On December 1, 2004, operations personnel issued CR-IP2-2004-06531, which identified that the No. 24 accumulator continued to leak (0.14 gallons per minute - which was calculated based on measured accumulator level loss). The CR also stated that this placed a burden on operators to continue to fill the tank on a daily basis. Operations continued to troubleshoot the system and eventually discovered that valve 839H, “24 Accumulator Test Valve,” was leaking. This valve is a 3/4 inch air operated valve located inside the vapor containment. It is normally closed during plant operation and opened only during refueling outages for leak testing certain RCS valves. Entergy personnel focused on preparing an action plan to perform additional testing to determine whether additional check valves were leaking. This plan included performing UT examination on the SI discharge headers to detect any gas buildup in the system.

On January 12, 2005, additional troubleshooting was performed which identified leakage through SI test line check valves 858A and 858B, and the No. 23 SI pump discharge check valve 849B. These valves are located in ECCS piping between the No. 24 accumulator and the SI pumps, and leakage past these valves represents a path of back-leakage between the No. 24 accumulator and the SI system. Following the discovery of these leaking check valves, two work orders were written to perform UT examinations of additional locations within the SI system. However, they were not completed for an additional two weeks.

On January 26, 2005, the required UT examinations were completed, and they indicated the presence of gas in the discharge piping of the SI system. Following this initial discovery of nitrogen gas in the SI system, the SI pump casings and suction lines were vented on January 27, 2005, to determine the extent-of-condition. During these evolutions, nitrogen gas was vented from the SI pump common suction header and from the casing of the No. 23 SI pump. Gas was also vented from the two discharge lines at the containment penetrations. The effects on past operability were unknown at this time because acceptance criteria for the amount of gas had not been established, nor was the gas volume known. The team noted that the Condition Review Group had evaluated the associated CR (CR-IP2-2005-00370) and appropriately classified it as a high priority ('A') requiring a complete root cause evaluation. Additional UT examinations and venting operations were performed. Specifically, a program to perform periodic UT examination and venting was implemented for selected SI piping locations, both inside and outside the vapor containment to ensure the SI system remained free from further gas accumulation.

Post Venting Condition. The team determined that there was reasonable assurance that the SI system was operable upon completion of the venting operations, which included the pump casings, and suction and discharge piping. Entergy subsequently developed a venting and UT examination plan, which provided sufficient monitoring to detect potential additional challenges concerning gas accumulation. The team noted that Entergy established a criterion of 5% void fraction (of pipe cross-sectional area) for safety injection system suction and discharge piping, at which point engineering would be engaged to conduct further evaluation. However, the team determined that this void fraction alone had not been established as being a reliably conservative acceptance value (void location, size, rate of change, etc. are additional factors that should be considered). Notwithstanding this weakness, given the conditions at the time of the onsite portion of the inspection (February 2005), the team did not have an operability concern because Entergy's ongoing monitoring and venting activities provided reasonable assurance that significant gas accumulation would not occur.

The team noted that prior to the gas intrusion event, Entergy was not well prepared for evaluating the impact of any gas at the suction to the SI pumps in that there was no guidance or available information to the operations staff in determining the effect of gas on the system (i.e., no technical specification requirements or periodic gas monitoring).

Entergy's Determination of As-found Gas Volumes and Void Fractions. Entergy determined the volumes of nitrogen gas found in the SI system suction and discharge piping and the 23 SI pump casing by two methods; UT measurements and calculational methods, which evaluated venting operations using orifice sizing equations. Entergy calculated that the maximum gas volume found in the SI common suction piping (including both the 8-inch and 6-inch sections at elevation 71'0") was 7.27 ft^3 (cubic feet), with a corrected gas volume of 6.57 ft^3. Entergy believed a correction factor was appropriate based on data they had collected that showed their calculated volumes associated with venting were conservatively higher than subsequent comparisons to UT measurements. Therefore, in their analysis of the gas void content for the suction piping, they used a correction factor of 1.2, which decreased their assumed volume of gas to 6.57 ft^3; and was based on an assumed reduction to the calculated volume relative to venting. The gas volume of 7.27 ft^3 correlated to a nominal void fraction estimate in the entire common suction header at the 71'0" elevation of 34%. That value resulted in a nominal 30% void fraction in the 6-inch horizontal lines that extended from the main suction header. Taking Entergy's assumed correction factor into consideration, the resulting void fractions would be 32% in the entire common header and 26% in the 6-inch horizontal lines leading from the main header.

The team noted through discussions with Entergy personnel that when initially performing UT measurements to estimate the gas, they would visually sight along an imagined horizontal line and would estimate the vertical distance between a mark on the pipe (the water level) and the top of the pipe. This technique was utilized between January 26 and February 21, 2005. This estimation method was the only technique used at the time when significant gas was in the SI piping, and the team determined that this method contained substantial measurement uncertainty. The team noted that Entergy had changed its method on February 21 to measure the circumferential distance around the pipe between determined locations ("arc method"). The team determined this to be of greater accuracy, but noted this method was not in use when the significant gas volume existed.

Due to the above-mentioned uncertainties regarding gas measurement technique, the team determined that it was appropriate to assume the higher gas volume content without the correction factor applied when assessing the as-found void content in the SI suction piping and 23 SI pump. With respect to the discharge piping, the team noted that Entergy's review of the as-found gas content indicated a nominal 34 standard ft^3 found in the discharge piping. Entergy performed an assessment of this condition, which concluded that the SI suction, discharge piping and supports would have remained operable with the as found gas volumes. The team similarly evaluated the condition with respect to water hammer/pipe and structural damage concerns, and did not identify any operability concerns.

Assessment of As-Found Gas Impact on SI Performance. The team reviewed IP-RPT-05-00110, "Past Operability Evaluation Summary - Nitrogen Gas Intrusion Event," dated April 27, 2005, which summarized evaluations performed by Entergy Nuclear Northeast Engineering and several vendors with respect to the effect that the as-found gas content would have had on system performance during an event. This document concluded that the ECCS continued to be capable of performing its safety function and that all regulatory limits were satisfied. These evaluations included reviews that considered stress analysis of piping and supports.

The evaluations also focused on determining pump performance with gas voids present in the piping system, and included calculations to determine the time required to purge the gas voids from the system piping to fully restore pump performance. Entergy utilized plant measurements, results of special tests from the industry, and evaluation of two phase flow phenomenon such as oscillating flow; and concluded that the nitrogen gas would be quickly purged from the system and the impact on pump performance would be acceptable. Various transients and accident scenarios were evaluated to estimate void fractions to the pumps and to evaluate the impact on the success criteria for the SI system.

The team reviewed Entergy's evaluations and performed independent calculations for void fraction content, potential void fractions entering the SI pumps, and various flowrate assumptions for postulated transient and accident scenarios. The team concurred with Entergy's earlier conclusion (on February 18, 2005[1]) that the as-found gas volume found in the 23 SI pump (which exceeded the calculated internal free volume of the pump) would have rendered the pump inoperable. The team evaluated the effect that the 34% void fraction in the common horizontal header would have had on the remaining two SI pumps (21 and 22). The team researched various operating experience documents, including test data results and analyses relative to the impact of gas on pump performance documented in NUREG /CR-2792, "An Assessment of Residual Heat Removal and Containment Spray Pump Performance Under Air and Debris Ingesting Conditions." The team also reviewed an IP-2 pump vendor position letter dated February 23, 2005, concerning the acceptability of various assumed void fractions on SI pump operation.

Based on these reviews, along with an independent analysis of the issue, the team could not conclusively determine with certainty that the 21 and 22 SI pumps would have failed to perform their function. In addition, the team noted that there were no technical specification requirements or limits for gas content in the suction or discharge piping of the system. Notwithstanding this, based in part on information in NUREG/CR-2792, the team determined that any increase above 2 to 5% void fraction at the pump inlet could begin to challenge the normal performance of the pumps. This was also consistent with the vendor's recommended position that operation should not occur with more than 5% gas by volume.

---

[1]Indian Point 2 Licensee Event Report No. 2005-002-00, dated April 14, 2005

The notable uncertainties in Entergy's evaluation of full pump functionality included; (1) uncertainties surrounding the assumptions on void fractions entering the pumps given the various postulated flowrates (i.e., void fraction at the pump inlet will increase as flowrate increases); and (2) the assumption that the pumps may degrade from their normal performance curve to the point where only minimum flowrate is achievable due to high reactor back-pressure, with a subsequent oscillatory response where the pump would be able to recover by purging the gas without becoming gas bound. Entergy's analyses had determined that as flowrate increases with decreasing backpressure for certain break sizes, gas begins to travel from the suction headers to the pumps. At some point, the pump performance would decrease due to the gas ingestion potentially resulting in only minimum flowrate back to its suction source (RWST), until the gas is cleared and the pump performance recovers.

The team was concerned that this postulated oscillatory pump response would result in very low flowrates (nominal 22-25 gpm) associated with the minimum flow line as pump discharge pressure would drop below vessel pressure. Given the lower velocity, there was increased uncertainty whether the pumps could purge the gas which may have equivalent or greater rise velocity. The same concern existed for assumed higher flowrates (i.e., 90 gpm and above) that would result during postulated accidents and transients as reactor backpressure decreases. The team determined that the assumption that gas would be cleared under these circumstances had not been conclusively demonstrated through Entergy's evaluations of the issue. However, the team agreed with Entergy's conclusion that the as-found condition did not represent certain failure of the SI system function.

NUREG/CR-2792 data for centrifugal pumps indicates that as void fractions increase above 2 to 5%, the performance of centrifugal pumps can begin to degrade. Also, the team noted that for a given void fraction, the performance can significantly drop off at pump flowrates well below the best efficiency points of the pumps. During the research of this issue, the team discovered that the NRC had previously evaluated an issue concerning the effects of entrained gas on the possible failure of low pressure ECCS pumps. During an assessment of Generic Safety Issue (GSI) 193, "BWR ECCS Suction Concerns Description," the NRC had utilized a developed curve that estimated a pump failure probability as a function of void fraction and time from initiation of the event. The curve, found in Figure 3.193-4 of the GSI study (Void Fraction and Pump Failure Probability vs. Time), was based on NUREG/CR-2792 information. The study concluded that at ingestion levels below 2%, pump degradation is not a concern for flows near rated conditions; for ingestion levels between 2% and 15%, performance is dependent on pump design; and for ingestion levels greater than about 15%, most pumps are fully degraded. The curve assumed a linear rise in pump failure probability from zero to unity between 2% and 15%.

Given that it was inconclusive as to the effect the as found gas would have had on 21 and 22 SI pump functionality, the team determined that a similar qualitative, yet technically informed, approach would best give an estimate of the risk of this issue. The team's evaluation recognized that there is an increased chance of pump failure probability for void fractions above 2%, especially at lower flowrates. The team calibrated the GSI pump failure probability range referenced in this study to better reflect the IP-2 multistage SI pump. The range considered; 1) industry operating experience which has indicated that gas has resulted in numerous examples of centrifugal pump failures; 2) NUREG/CR-2792 data and trends which indicated as void fractions increase at the pump inlet, pump performance degradation likely will increase; 3) NUREG/CR-2792 Figure 3-9 which documented that for a given void fraction, multistage pump performance (IP2 SI pumps are 10 stage pumps) is less degraded than single stage pumps; and 4) the pump vendor position regarding operation with elevated void fractions (that there is a good chance of pump seizure at elevated void fractions of a nominal 20%). The consideration of the above information resulted in the utilization of a probability of failure range from 0-75% which was correlated to a void fraction at the pump inlet of 5-20%. The team then developed a linear probability of failure curve based on this range, similar to the GSI approach.

The team performed calculations and best estimates for flowrates and void fractions at the pump inlets for various transient and accident conditions. This resulted in the determination that the 21 and 22 SI pumps would be assigned a probability of failure of 25% due to a nominal 10% void fraction being predicted at the pumps for small break LOCAs and equivalent transients. The team noted for medium break and large break scenarios, the SI flowrate will be much higher and thus a higher void fraction would be assumed to enter the pumps. For these scenarios, a 75% probability of failure was assigned to represent a good chance of failure. The team believed this would render a conservative estimate of the risk increase, as these failure rates were higher than the normal estimated probability of failures for these pumps typically assigned under non degraded conditions (i.e., on the order of 0.1% probability of failure).

In conclusion, the team found that Entergy's evaluations did not provide conclusive assurance that the as-found gas content would result in the SI pumps being fully capable of performing their safety function. The team concluded that an assessment of the risk of the issue, utilizing available data and operating experience, indicated that as void fractions increase, the performance of a pump degrades and hence the probability of pump failure increases. The methodology utilized was believed to provide a reasonable estimate of the risk as the probability of failure for the pumps was increased several orders of magnitude from their normal levels. This was then utilized to determine a change in the core damage frequency (CDF) as a result of the performance deficiency, and is outlined in detail in the analysis section.

Analysis. The performance deficiency involved the failure to evaluate and correct a condition adverse to quality as required by 10 CFR, Part 50, Appendix B, Criterion XVI (Corrective Action) and Entergy's corrective action system procedure EN-LI-102, "Corrective Action Process." Specifically, the condition involved leakage of water from the No. 24 SI accumulator past several closed valves, allowing water containing absorbed nitrogen to reach other portions of the SI system (including the common suction supply piping for the SI pumps and the 23 SI pump casing). As the water moved from a higher to lower system pressure, the nitrogen gas was released from the water, thereby challenging the performance of the safety injection pumps. This deficiency was indicative of cross-cutting weaknesses in the area of problem identification and resolution (evaluation and corrective action).

The finding was more than minor because it is associated with the Equipment Performance attribute of the Mitigation Systems cornerstone and affected the objective to ensure the availability, reliability, and capability of the SI system to respond to an initiating event. In accordance with NRC Inspection Manual Chapter (IMC) 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the team performed a significance determination process (SDP) Phase 1 screening. The finding resulted in degradation of short-term core decay heat removal capability provided by the SI system in the initial injection mode of operation. The finding also resulted in degradation in long-term core decay heat removal capability of the SI system when used in the sump recirculation mode of operation.

The condition was discovered on January 27, 2005. This was 34 days ('T,' or time) following the last successful quarterly surveillance test (December 24, 2004) of the No. 23 SI pump. The team agreed with Entergy's conclusion that the No. 23 SI Pump was nonfunctional at the time the gas was discovered in the pump casing. Based upon a review of all available information and data, it was not apparent when the No. 23 SI pump became nonfunctional. Therefore, the T/2 approximation was used to conclude that the exposure time for the degraded condition was 17 days, which is consistent with guidance found in NRC IMC 0609, Appendix A. The SI system is comprised of three 50-percent capacity pumps. The technical specification allowed outage time (AOT) for one pump is 72 hours. Therefore, the finding represented an actual loss of safety function of a single train for greater than its AOT, and an SDP Phase 2 evaluation was required.

Nitrogen gas was also identified in the common suction piping for all three SI pumps (21, 22 and 23). The team noted that any reduction below 100 percent of the emergency core cooling system flow equivalent of the remaining two SI pumps would result in a loss of the SI safety function as described in the technical specifications.

The senior risk analyst (SRA) performed a bounding modified Phase 2 evaluation using the Risk-Informed Inspection Notebook for Indian Point Nuclear Generating Station, Unit 2, Revision 1. An exposure time of greater than three days and less than 30 days was used consistent with the T/2 exposure time approximation. The 23 SI pump was considered nonfunctional for all initiators. Based on the flowrate and pressure that would occur, the team developed "best estimate" initiator-dependent failure probabilities for the 21 and 22 SI pumps, as follows.

- Low Flow, High Pressure - The failure probability of the 21 and 22 SI pumps was assumed to be 0.25 each; for initiators where flowrate would be low and discharge pressure high such as SLOCA, SGTR, and SORV and for transients that can result in an SORV such as TRANS, TPCS, LOOP, LCCW, and LNCW;

- High Flow, Low Pressure - The failure probability of the 21 and 22 SI pumps was assumed to be 0.75 each for MLOCA and MSLB; and

- No recovery was credited in any case.

If the failure probability of the 21 and 22 SI pumps was 0.25, the SRA used a remaining mitigation capability credit of 1 for the HPI and HPR safety function. If the failure probability of the 21 and 22 SI pumps was 0.75, the SRA used a remaining mitigation capability credit of 0 (i.e., no credit) for the HPI and HPR safety functions.

All worksheets except LLOCA, ATWS and LBDC were evaluated and resulted in an internal event delta (increase) in core damage frequency (ΔCDF) in the low E-4 per year range. The SRA recognized that these results were neither accurate nor particularly meaningful given the gross assumptions made relative to remaining SI mitigation credit. Therefore, the SRA performed a Phase 3 SDP evaluation.

The Phase 3 analysis discussed below, for internal and external initiating events, estimated a ΔCDF in the low-E-6 range and a delta (increase) in large early release frequency (ΔLERF) in the mid-E-7 range. As such, the finding had low to moderate safety significance (White).

<u>ΔCDF</u>

The Indian Point Nuclear Generating Station, Unit 2, Standardized Plant Analysis Risk (SPAR) Model, Revision 3.11, was used. The 23 SI pump was failed by setting the failure-to-run term, HPI-MDP-FR-23 to true. Failure probabilities for the 21 and 22 SI pumps were set to 0.75 for MLOCA and 0.25 for all other initiators. The SPAR model was modified to credit the ability of the operators to depressurize the reactor coolant system and use low-pressure systems upon failure of the SI pumps. For a 17-day exposure period, the resulting ΔCDF was in the mid-E-7 range. The risk increase was dominated by a LOOP event with a stuck open PORV and failure of the SI pumps, and an SGTR event, with failure to isolate the ruptured steam generator and failure to cooldown and depressurize after failure of the SI pumps. The SPAR model did not include an analysis of MSLB initiators. However, a preliminary analysis performed by the licensee indicated that an MSLB could induce an SGTR. The licensee's MSLB contribution was in the low-E-7 range and the SRA concluded it appeared to be a reasonable estimate.

The analysis also included a review of external initiating events. An internal flooding event requiring a plant shutdown using the alternate safe shutdown system contributed in the mid-E-7 range to the ΔCDF total. Other external events (fire, external flooding, high winds, and earthquakes) did not contribute significantly to the total increase in CDF.

<u>ΔLERF</u>

Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," was used to evaluate the impact of the performance deficiency on the LERF. The relevant Appendix H factors relevant to this issue involve SGTR sequences because they result in containment bypass. Appendix H applies a multiplier of 1.0 for significant SGTR sequences. The SRA estimated that the ΔLERF for this finding was in the low-to-mid-E-7 range.

Review of Entergy's Analysis

As stated above, the SRA also reviewed the results of a preliminary analysis performed by the licensee. This analysis used the same failure probability assumptions used in the SPAR analysis and the same exposure time. In many respects, the results were similar. However, the LOOP analysis was not comparable due to a difference in modeling. The SPAR model does not credit the ability to cooldown and depressurize if a PORV is stuck open. Nevertheless, given common assumptions regarding the SI pump failure probabilities, it was concluded that the licensee's results were reasonably consistent with the preliminary SDP results.

Enforcement. Criterion XVI, "Corrective Action," of 10 CFR 50, Appendix B, Criterion XVI (Corrective Action) requires, in part, that conditions adverse to quality be promptly identified and corrected. Entergy's corrective action system procedure EN-LI-102, "Corrective Action Process," similarly requires, in part, the identification, evaluation and correction of a broad range of problems; and to document both previous (in-house) and industry Operating Experience Reviews, when appropriate (commensurate with safety significance).

Contrary to the above, between November 21, 2004 and January 27, 2005, Entergy failed to promptly evaluate and correct a condition adverse to quality regarding the potential for gas intrusion into the safety injection system discharge and suction piping from known leakage from the 24 safety injection accumulator. A contributing cause of the failure to properly address the condition was a failure to adequately assess and evaluate operating experience in accordance with the expectations of Entergy's corrective action process. Specifically, operating experience (such as NRC Information Notice 97-40) related to SI accumulator backleakage was not assimilated and acted upon in a timely fashion. **(AV 05000247/2005006-02, Failure to Adequately Evaluate and Correct Nitrogen Gas Migration and Accumulation in Portions of the Safety Injection System)**

2. Routine Review of Identification and Resolution of Problems

a. Inspection Scope

The team assessed whether Entergy personnel were identifying issues at the proper threshold and entering them in the corrective action program by reviewing a sample of CRs associated with the RHR, SI, Recirculation and main steam systems. The team's selection of items to review focused on design related issues which may have an effect on the design bases capabilities of the selected systems. In addition, the team reviewed a sample of condition report operability determinations and condition report follow-up actions to verify that problems were identified, documented, and effectively resolved.

b. Findings

While no findings of significance were identified during this routine review, see Section 4OA2.1 for a detailed description of a finding associated with inadequate evaluation and correction of a condition adverse to quality.

4OA4 Cross Cutting Aspects of Findings

Section 4OA2.1 of this report describes a finding where plant staff did not properly evaluate and correct a degraded condition in the safety injection system, and was indicative of a cross-cutting weakness in the area of problem identification and resolution (evaluation and corrective action).

4OA5 Other

(Closed) URI 50-247/02-010-005: Environmental Qualification of Reactor Coolant System Narrow Range Resistance Temperature Detectors

During a supplemental and problem identification and resolution inspection in July 2002, NRC staff had identified a concern related to the need for the reactor coolant system (RCS) narrow range resistance temperature detectors (RTD) to be environmentally qualified (EQ). NRC staff identified that the RTDs were excluded from the EQ program even though the USFAR credited their operation during a main steam line break accident. This issue was left unresolved pending NRC review of the licensee's evaluation.

The team reviewed this concern through a review of Entergy's associated evaluation, which was documented in Condition Report IP2-CR 2002-06777. The evaluation determined that the qualification issue was acceptable because the redundant initiation signal (low steam line pressure) for the same safety injection function was EQ and was credited for this function. Further, Entergy initiated a change to the UFSAR Section 14.2.5, eliminating the need to credit the signal from the RCS RTDs. The team determined that Entergy's evaluation adequately addressed the concern; and no findings of significance were identified. Based on this review, the team considered this item closed.

4OA6 Meetings, Including Exit

1. Management Meeting

A preliminary exit meeting was conducted on March 4, 2005, when the team presented the preliminary inspection results with Mr. F. Dacimo and other Entergy staff members. However, additional onsite and in-office inspection activities continued following the preliminary exit meeting through April 27, 2005. The team presented the completed inspection results to Mr. C. Schwarz and other members of Entergy staff during a telephone exit meeting on May 18, 2005. The team reviewed some proprietary information during the inspection; and this material was either returned to Entergy personnel or was destroyed. The team verified that this inspection report does not contain proprietary information.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
J. Bencivenga, Senior Nuclear Engineer, Design Engineering
C. Bergren, Senior Engineer, Programs and Components
V. Cambigianis, System Engineering Supervisor
T. Carson, Maintenance Manager
G. Dahl, Technical Specialist, Licensing
J. Etzweiler, Operations Coordinator
C. Ingrassia, System Engineer
A. Irani, Supervisor, Nuclear Engineering Analysis
T. Jones, Licensing Supervisor
E. Kenney, MOV Program Engineer
T. McCaffrey, System Engineering Manager
R. Parks, Operations EOP Coordinator
S. Petrosi, Design Engineering Manager
D. Shah, System Engineer
M. Yee, Senior Engineer, Design Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50–247/05-06-02	AV	Failure to Adequately Evaluate and Correct Nitrogen Gas Migration and Accumulation in Portions of the Safety Injection System (Section 4OA2.1)

Closed

50-247/02-10-005	URI	Environmental Qualification of Reactor Coolant System Narrow Range Resistance Temperature Detectors (Section 4OA5)

Opened and Closed

50-247/05-06-01	NCV	Non-Conservative Post-Accident Recirculation Pump Motor Loading Conditions Used to Determine Overload Trip Settings for 480 Volt Type DB Circuit Breakers (Section 1R21)

LIST OF DOCUMENTS REVIEWED

Procedures

2-AOP-CCW-1	Loss of Component Cooling Water, Rev. 1
2-AOP-SG-1	Steam Generator Tube Leak, Rev. 2
2-OPS-10.1.1	Support Procedure - SI Accumulators and RWST Operations, Rev. 13
2-POP-3.2	Plant Recovery from Trip, Mode 3, Rev. 32
2-PT-Q13	Quarterly Surveillance Test, Rev. 0
2-PT-R006	Main Steam Safety Valve Setpoint Determination, Rev. 23
2-PT-R013A	Recirculation Switches, Rev. 14
2-PT-V024E	Main Steam Isolation Valves, Rev. 3
2-PT-V024K	Main Steam Non Return Check Valves, Rev. 3
2-SOP-10.1.1	SI Accumulators and Refueling Water Storage Tank Operations, Rev. 45
2-SOP-18.1	Main and Reheat Steam System Operation, Rev. 33
2-SOP-4.2.1	Component Cooling System Operation, Rev. 28
3-SOP-SI-001	IP3 Safety Injection System Operations, Rev. 32
AOI 4.2.3	Transfer to Cold Leg Recirculation During LOCA, Rev. 5
E-0	Reactor Trip or Safety Injection, Rev. 45
E-1	Loss of Reactor or Secondary Coolant, Rev. 42
E-2	Faulted Steam Generator Isolation, Rev. 39
E-3	Steam Generator Tube Rupture, Rev. 43
ECA-1.1	Loss of Emergency Coolant Recirculation, Rev. 43
ENN-DC-197	Integrity of Systems Outside PWR Containment, Rev. 0
ES-0.0	Rediagnosis, Rev. 39
ES-1.1	SI Termination, Rev. 42
ES-1.2	Post LOCA Cooldown and Depressurization, Rev. 41
ES-1.3	Transfer to Cold Leg Recirculation, Rev. 41
ES-1.4	Transfer to Hot Leg Recirculation, Rev. 40
FR-H.1	Response to Loss of Secondary Heat Sink, Rev. 41
MSL-B-009-N	Chesterton Seals Non Class ‘A’ Installation Instructions, Rev. 3
OAP-012	EOP Users Guide, Rev. 1
OAP-038	Operations Mechanical Equipment Guidelines, Rev. 2
OASL 15.69	Fuse Control Program, Rev. 0
PT-Q29C	23 Safety Injection Pump, Rev. 14
SE-SQ-12.312	MOV Limit Switch Setting Control, Rev. 7

Completed Surveillances

PT-2M 4	SI System Train ‘A’ Actuation Logic and Master Relay Test (2/01/04)
PT-2M 5	SI System Train ‘B’ Actuation Logic and Master Relay Test (12/20/04)
2-PT-R014	Automatic SI System Electrical Load and Blackout Test (10/22/01)
2-PT-Q13	Inservice Valve Tests (December 2004)
2-PT-V024	Inservice Valve Tests (11/13/04)
PT-V24E	Main Steam Isolation Valves (11/13/04)
PT-Q29A	21 SI Pump Quarterly Test (10-31-04)
PT-Q29B	22 SI Pump Quarterly Test (12-10-04)

PT-Q29C 23 SI Pump Quarterly Test (12-24-04)

Drawings

1999MC3365	Containment Recirculation Pumps and NPSH Curves
9321-F-2017-83	Flow Diagram Main Steam, Rev. 1/13/88
9321-F-2735-136	Safety Injection System, Rev. 2/12/88
9321-F-3006-92	Single Line Diagram 480V MCC 26A and 26B, Rev. 9/8/02
9321-LL-3131-12	Schematic Diagram MSIVs - Sheet 21, Rev. 1/30/03
A200773	Nuclear Tank Farm Composite Piping, Rev. 12/2/03
A235296-63	Safety Injection System, Rev. 11/20/04
A251783-28	Auxiliary Coolant System RHR Pumps, Rev. 4/10/03
CF-SP-99944-1	Safety Injection Pump, Rev. 0
D252859-02	Main Steam Stop Isolation Valve MS-1-21, Rev. 2/01/99
D32549	Chesteron Seal, Rev. 0
B244131-4	Safety Injection System Pumps 21, 22 and 23

Calculations

60817-6	480 Volt DB Circuit Breaker Settings for 350 HP Recirc
99621-C-002	Motor Operated Valve Terminal Voltage, Rev. 3
CN-CRA-03-20	IP2 Steamline Break Inside Containment Analysis for Stretch Power Uprate, Rev. 0
CN-CRA-03-37	IP2 SG Tube Rupture Analysis for Uprate Program, Rev. 0
CN-LIS-03-101	ECCS Flows, Rev. 0
CN-SCS-03-29	Steamline Pressure – Low ESFAS Steamline Isolation Actuation Setpoint Uncertainty Calculations for IP2 (4.7% Uprate program), Rev. 10/13/03
CN-SEE-00-63	Diesel Loading Study - Pumps, Rev. 1
CN-TA-02-106	Steamline Break Core Response Evaluation for Increased Steamflow Setpoint and Low Tavg Setpoint Elimination, Rev. 0
CN-TA-03-132	Excessive Load Increase for Stretch Power Uprate, Rev. 0
CRA-03-48	Supplemental Steam Generator Tube Rupture Analysis, Rev. 1
CRA-03-63	SG Tube Rupture Radiological Consequences Analysis, Rev. 1
ER-IP2-04-34915	Containment Recirculation Pumps Surveillance Test Acceptance Criteria for Strong Pumps
FEX-00039-02	EDG Loading Study, Rev. 2
FEX-00084-00	Consolidated Edison - IP-2 MOV Motor Impedance and Terminal Voltage, Rev. 7/07/97
FIX-00030-02	Nitrogen Backup System Capacity to Support Critical AFW System ACR Users in the Event of Loss of Instrument Air, Rev. 3/1/00
FMX-00126-00	SI System Recirculation Analysis Report, Rev. 0
FMX-0036-03	Safety Injection Recirculation Pump Available NPSH, Rev. 3
FMX-97-12451-M	IP2 MOV Pressure Equalization
IP-CALC-05-00059	Estimate of Gas Volume Quantity Found in SI Piping, Rev. 3
IP-CALC-05-00390	Evaluation of SI Pump Flow Oscillation Due to Gas Intrusion After SBLOCA, Rev. 0

IP-RPT-05-00110	Past Operability Evaluation Summary-Nitrogen Gas Intrusion Event, Rev. 0
MMS-00004	SI and RHR Pump Room Temperatures / Effects on Qualified Life of EQ MOV(s), Rev. 0
MMS-00096	Analysis of Thrust and Torque Limits for MOV 842, Rev. 11
MMS-00097	Analysis of Thrust and Torque Limits for MOV 843, Rev. 9
MMS-00120	Analysis of Thrust and Torque Limits for MOV 888A, Rev. 10
MMS-00121	Analysis of Thrust and Torque Limits for MOV 888B, Rev. 10
MMS-00134	Analysis of Thrust and Torque Limits for MOV 1802A, Rev. 8
MMS-00135	Analysis of Thrust and Torque Limits for MOV 1802B, Rev. 9
MMS-00136	Analysis of Thrust and Torque Limits for MOV 1810, Rev. 10
PGI-00020	1802A/B Differential Pressure Vendor Calculation 32-1206439-03, Rev. 1
PGI-00047	842&843 Differential Pressure Vendor Calculation 32-1213630-02, Rev. 1
PGI-00052	1810 Differential Pressure Vendor Calculation 32-1213633-02, Rev. 1
PGI-00066	888 A/B Differential Pressure Vendor Calculation 32-1206442-03, Rev. 1
PGI-00218	External Recirculation and RWST Leakage Allowances, Rev. 0
PGI-00472	Altran Calculation #01004-C-001: 480V MCC Bus Degraded Voltage, Rev. 2
SGX-00048-01	IP-2 480V Switchgear Coordination Calculation
SGX-00059-01	Safety Related 480V MCC Coordination Calculation for MCC 26A, Rev. 1
WCAP-15823	EOP Setpoint SP1-B.7, Wide Range RCS Pressure, Rev. 1
WCAP-16157-P	Licensing Report, Rev. 0

Miscellaneous Documents

3/3/86 Memo (R. Spring to J. Grob), Qualification Requirements for RCS Narrow Range RTDs
Chemical Engineering Study, “Downflow in Vertical Piping,” June 17, 1968
DBD, RHR and SI Systems, Rev. 0
DBD, Main Steam System, Rev. 0
EOP E-0 Background Information Document, Rev. 6/3/02
EOP E-2 Background Information Document, Rev. 6/3/02
EOP E-3 Background Information Document, Rev. 6/3/02
ER 04-2-005, Replacement of RCS Narrow Range Temperature Measuring System, Rev. 0
Estimate for 125VDC Distribution Panel 21 Circuit 20 MSIV Loads, 3/2/05
Evaluation of Gas Intrusion Into SI System and Effects on Pump/System Performance at IP-2
FMX-99-12055-M, Containment Recirculation Pumps Replacement
IP-2 Inservice Testing Program Basis Data Sheets for Valves 847 and 1810
IST Program Basis Data Sheet For Valves 849B, 847, 1810, 746, and Recirculation Pumps
L801-19-001, Engineering Review to Determine Whether Any Non-Safety Related Equipment Requires Qualification Pursuant to 10 CFR 50.49, IP-2, Rev. 1 (March 1986)
Lesson Plan ES-500-0800, SG Pressure Failure/LOOP/SGTR, Rev. 3
Modification Procedure for Class ‘A’ Work, Replacement of MSIV 9" Air Cylinder Operators with 12" Air Cylinders, March 25, 1976
NL 98-038, Response to Safety Evaluation-Joint Owner’s Group Program on Periodic Verification of MOVs (in response to Generic Letter 96-05), 4/30/98
NL 97-036, 180 Day Response to US Nuclear Regulatory Commission Generic Letter 96-05
NL-88-092, IP-2 Response Letter to NRC Generic Letter 88-04, 7/19/88

NUREG/CR-2792, An Assessment Of RHR and Containment Spray Pump Performance Under Air and Debris Ingesting Conditions
NUREG-0897, Containment Emergency Sump Performance
NUREG-0933, NRC: A Prioritization of Generic Safety Issues, ISSUE 193
OAP-012, EOP Users Guide, Rev. 1
Operations and Maintenance Manual - Pacific Pump Type JTC (945-J50641)
Operator Log Entry Reports for 1/28/05-1/31/05 and 2/20/05-2/21/05
PQE-54.1, Resistance Temperature Detector, Rev. 0
Safety Evaluation 90-334-MD, EDG Upgrade, Rev. 4
Sequence of Events Summary for Gassing Issue from 11/21/04 - 1/31/05
System Component Evaluation Worksheet, EQ of SI System Components, 3/21/86
System Description No. 10.1, Safety Injection System, Rev. 10
System Description No. 4.2, Residual Heat Removal Loop, Rev. 6
TR-9462, Ingersoll-Dresser [RHR] Pump Performance & Thrust Test Report, Rev. 0
UFSAR (Multiple Sections), Rev. 18
USFAR Change Request 1153
Valve Thrust Traces for Valves 842, 1802A, 843, 1802B, 888A, 1810 and 888B

Condition Reports

1996-00221
1996-01075
1997-02798
1998-00252
1998-05607
2001-00599
2001-00943
2001-07780
2001-07780
2002-00276
2002-06777
2002-10824
2004-05076
2004-05076
2004-05532
2004-05718
2004-05784
2004-05820
2004-06065
2004-06125
2004-06556
2005-00370
2005-00415
2005-00420
2005-00423
2005-00427
2005-00428
2005-00742
2005-00802
2005-00908
2005-00920

Work Orders

IP2-03-10267
IP2-03-26821
IP2-03-27176
IP2-04-31754
IP2-04-34076
IP2-04-35313
IP2-05-00383
IP2-05-11429

LIST OF ACRONYMS

ΔCDF	Delta (increase) in Core Damage Frequency
ΔLERF	Delta (increase) in Large Early Release Frequency
AOT	Allowable Outage Time
BWR	Boiling Water Reactor
CFR	Code of Federal Regulations
CR	Condition Report
DBD	Design Basis Document
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EQ	Environmentally Qualified
ft^3	Cubic Feet
GSI	Generic Safety Issue
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IP-2	Indian Point Nuclear Generating Unit No. 2
kV	kiloVolt
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MCC	Motor Control Center
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PI&R	Problem Identification and Resolution
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RTD	Resistance Temperature Detectors
RWST	Refueling Water Storage Tank
SDP	Significance Determination Process
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SRA	Senior Risk Analyst
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Test
V	Volts