January 27, 2000

Mr. Robert J. Barrett
Site Executive Officer
New York Power Authority
Indian Point 3 Nuclear Power Plant
Post Office Box 215
Buchanan, NY 10511

SUBJECT: NRC INTEGRATED INSPECTION REPORT NO. 05000286/1999009

Dear Mr. Barrett:

On December 13, 1999, the NRC completed an inspection at your Indian Point 3 reactor facility. The enclosed report presents the results of that inspection. During the seven-week period covered by the inspection, your staff conducted activities at the Indian Point 3 reactor facility with an adequate focus on safe plant operations.

The NRC noted that you independently began trending an increasing number of out-of-position valves and breakers in December which we regarded as a good initiative. While this initial effort was good, the screening criteria used to identify configuration control issues was initially somewhat narrow to identify all instances for evaluation. In addition, management attention is needed to ensure that core reload activities including actions to update the reload analysis are accurate and implemented in a timely manner. The NRC noted a number of problems in this area after restart from your fall 1999 refueling outage.

Your review of the complications related to the Indian Point 2 reactor trip on August 31, 1999, for the purpose of assessing what actions, if any, should be taken to prevent a similar event at Indian Point 3 was acceptable. However, our review of the degraded grid voltage analysis found that the current undervoltage relay set point calculations were not adequate and that the minimum voltage specified in the technical specification was too low to ensure the correct operation of some components under postulated accident conditions concurrent with a degraded grid voltage.

Should you have any questions regarding this report, please contact me at 610-337-5234.

Sincerely,

/RA by John F. Rogge Acting For/

Peter W. Eselgroth, Chief
Projects Branch 2
Division of Reactor Projects

Docket No. 05000286
License No. DPR-64

Enclosure: Integrated Inspection Report No. 05000286/1999009

cc w/encl:
C. D. Rappleyea, Chairman and Chief Executive Officer
E. Zeltmann, President and Chief Operating Officer
R. Hiney, Executive Vice President for Project Operations
J. Knubel, Chief Nuclear Officer and Senior Vice President
F. Dacimo, Plant Manager
H. P. Salmon, Jr., Vice President of Engineering
W. Josiger, Vice President - Special Activities
J. Kelly, Director - Regulatory Affairs and Special Projects
T. Dougherty, Director - Nuclear Engineering
R. Deasy, Vice President - Appraisal and Compliance Services
R. Patch, Director - Quality Assurance
G. C. Goldstein, Assistant General Counsel
C. D. Faison, Director, Nuclear Licensing, NYPA
K. Peters, Licensing Manager
A. Donahue, Mayor, Village of Buchanan
J. McCann, Department Manager of Nuclear Safety and Licensing
C. W. Jackson, Con Edison
C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
Chairman, Standing Committee on Energy, NYS Assembly
Chairman, Standing Committee on Environmental Conservation, NYS Assembly
T. Morra, Executive Chair, Four County Nuclear Safety Committee
Chairman, Committee on Corporations, Authorities, and Commissions
The Honorable Sandra Galef, NYS Assembly
P. D. Eddy, Electric Division, Department of Public Service, State of New York
G. T. Goering, Consultant, New York Power Authority
J. E. Gagliardo, Consultant, New York Power Authority
E. S. Beckjord, Consultant, New York Power Authority
F. William Valentino, President, New York State Energy Research
and Development Authority
J. Spath, Program Director, New York State Energy Research
and Development Authority

Distribution w/encl:

H. Miller, RA/J. Wiggins, DRA (1)
Region I Docket Room (with concurrences)
Nuclear Safety Information Center (NSIC)
PUBLIC
NRC Resident Inspector
P. Eselgroth, DRP
S. Barber, DRP
L. Harrison, DRP
R. Junod, DRP

Distribution w/encl: **(VIA E-MAIL)**
T. Bergman, RI EDO Coordinator
E. Adensam, NRR
G. Wunder, NRR
J. Harold, NRR
Inspection Program Branch, NRR (IPAS)
W. Scott, NRR
R. Correia, NRR
DOCDESK

DOCUMENT NAME: G:\BRANCH2\IP3/IP39909.WPD
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/DRP	N	RI/DRP	N
NAME	PDrysdale/PE for		PEselgroth/PE	
DATE	1/27/00		1/27/00	

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	05000286
License No.	DPR-64
Report No.	05000286/1999009
Licensee:	New York Power Authority
Facility:	Indian Point 3 Nuclear Power Plant
Location:	P.O. Box 215 Buchanan, New York 10511
Dates:	October 25 - December 13, 1999
Inspectors:	Peter Drysdale, Senior Resident Inspector Lois James, Resident Inspector Leonard Prividy, Senior Reactor Engineer Neil Della Greca, Senior Reactor Engineer
Approved by:	Peter Eselgroth, Chief Projects Branch 2 Division of Reactor Projects

EXECUTIVE SUMMARY

Indian Point 3 Nuclear Power Plant
NRC Integrated Inspection Report No. 05000286/1999009

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covered a seven-week period of resident inspections, and included inspections by region-based specialists in operations and engineering.

Operations:

The NRC noted that you independently began trending an increasing number of out-of-position valves and breakers in December which we regarded as a good initiative. While this initial effort was good, the screening criteria used to identify configuration control issues was initially somewhat narrow to identify all instances for evaluation (Section O1.1).

The operations staff demonstrated good overall performance and good procedural adherence during shift and position turnovers. The inspectors considered the licensee's shift turnover process to be an organizational strength. During a plant tour, the inspector observed that operators demonstrated good knowledge of the status of plant equipment (Section O1.2).

NYPA's overall response to GL 98-02, "Loss of Reactor Coolant Inventory and Associated Loss of Emergency Mitigation Functions While in a Shutdown Condition," was acceptable. This included precautions added to heatup and cooldown procedures to prevent inadvertent opening of isolation valves that could result in an alignment comparable to the Wolf Creek event. However, initial actions taken in late 1998 were not comprehensive, such as a lack of consideration of human factors to ensure positive configuration control of the RCS boundary. NYPA issued appropriate Deviation/Event Reports to correct this weakness and to meet the intent of the requested actions in GL 98-02 (Section O7.1).

Maintenance:

Maintenance activities observed were conducted satisfactorily and in accordance with applicable maintenance and administrative procedures. The corrective maintenance performed was satisfactory to resolve the deficient conditions and the post maintenance testing was adequate to determine the effectiveness of the repairs. The licensee appropriately monitored performance of equipment within the scope of the maintenance rule and re-evaluated preventive maintenance frequencies based on equipment performance (Section M1.1).

The recurring problem with Problem Identification Description tags remaining in the plant and control room after work has been completed, rejected, or canceled represented a weakness in the licensee's work control process and caused unnecessary actions by operators to troubleshoot abnormal equipment conditions (Section M1.2).

Routine surveillance tests were conducted appropriately and in accordance with procedural and administrative requirements. Test and performance monitoring personnel maintained a good level of communication and coordination with control room operators during observed surveillance tests. Test instrumentation was within the required calibration periods and all test acceptance criteria for operability were met (Section M1.3).

Independent calculations by the inspectors confirmed that the licensee's core thermal power calculations were technically accurate based on the data inputs that were used. However, the licensee did not provide a formal basis for the use of a non-qualified instrument (i.e., plant computer) in order to verify compliance with the Technical Specification limit on core thermal power. This item will remain unresolved pending further NRC review of the licensee's basis for its use in meeting Technical Specification requirements (Section M1.4).

Engineering:

Reactor engineering was slow to update reactivity tables in operating procedures and the full power zero axial offset detector currents in the plant computer after the plant achieved full power following the last refueling outage. The use of outdated tables and incorrect detector currents resulted in unanticipated core temperature responses following blended boron additions to the reactor coolant system, and during a plant power reduction. Operators took appropriate actions in response to minor Tave increases and the unexpected core responses. No power or significant temperature transients resulted and the operators were able to maintain maximum Tave below the Technical Specification limit (Section E2.1).

The licensee conducted an acceptable review of the August 31, 1999, Indian Point 2 reactor trip complications for the purpose of assessing what actions, if any, should be taken to prevent a similar at Indian Point 3 (IP3); and had initiated appropriate actions to ensure that IP3 would not be vulnerable to a similar event (Section E2.2).

The licensee justified the operability of the electrical system under normal operating conditions. However, several opportunities were missed in the past to verify the adequacy of and correct the Technical Specification-defined minimum voltage at the 480 Volt buses. The missed opportunities were the result of inadequate review of licensee or contractor-prepared calculations. The issues regarding the minimum required voltage at the 480 Volt buses and the required relay settings are unresolved pending the licensee's calculations to address the voltage drop from the motor control center to the motor starter coils and the accuracy of the voltage sensing circuit (Section E2.3).

The overall material condition of the emergency diesel generators (EDGs) was good. The EDG equipment appeared to be properly maintained and in adequate working condition. The system engineer was knowledgeable of the equipment condition, problems, and maintenance associated with the EDGs.(Section E2.4).

Executive Summary (cont'd)

Plant Support

The licensee's actions were effective in removing a large volume of rain water that leaked into the primary auxiliary building (PAB), and to cleanup the resulting spread of contamination into an uncontrolled area. The causes of the storm drain blockage were satisfactorily addressed by establishing a regular scheduled activity to inspect and cleanout storm drains outside the PAB (Section R1.1).

TABLE OF CONTENTS

EXECUTIVE SUMMARY ii

TABLE OF CONTENTS v

SUMMARY OF PLANT STATUS 1

I. OPERATIONS 1
- O1 Conduct of Operations 1
  - O1.1 Multiple Plant Components Found Out-of-Position 1
  - O1.2 Shift Turnovers and Control Room Observations 2
- O7 Quality Assurance in Operations 3
  - O7.1 Response to Generic Letter 98-02 3

II. MAINTENANCE 5
- M1 Conduct of Maintenance 5
  - M1.1 Maintenance General Comments 5
  - M1.3 Surveillance General Comments 11

III. ENGINEERING 13
- E2 Engineering Support of Facilities and Equipment 13
  - E2.1 Cycle-11 Core Reactivity Management 13
  - E2.2 NYPA's Evaluation of the Reactor Trip at Indian Point 2 on August 31, 1999 16
  - E2.3 Degraded Grid Relay Settings (URI 05000286/199900902) 17
  - E2.4 System Engineering Review of EDG Deficiencies 21
- E8 Miscellaneous Engineering Issues 21
  - E8.1 (Closed) Inspection Follow-up Item (IFI) 0500286/19988001, "Incorporate EPRI PPM results into Design Calculations." 21

IV. PLANT SUPPORT 22
- R1 Radiological Protection and Chemistry (RP&C) Controls 22
  - R1.1 Rainwater Leakage into the Primary Auxiliary Building and Spread of Contamination 22
- X1 Exit Meeting Summary 23

ATTACHMENTS

Attachment 1
- Partial List of Persons Contacted
- Inspection Procedures Used
- Items Opened, Closed, and Discussed
- List of Acronyms Used

Report Details

SUMMARY OF PLANT STATUS

At the beginning of the inspection period on October 25, 1999, the Indian Point 3 plant was online and at 80% power in a normal power ascension following refueling outage number 10. The plant achieved full power on October 27, 1999. On November 3, plant power was reduced to approximately 6% and the unit taken offline to replace two rubber diaphragms in the main turbine trip oil pressure sensing unit. Following those repairs, the plant was returned to 100% power on November 6. On November 12, plant power was reduced to approximately 95% in an attempt to reduce high vibrations on the 31 main boiler feed pump (MBFP). On November 13, plant power was further reduced to approximately 60% to remove the 31 MBFP from service to troubleshoot the high vibrations. Following 31 MBFP maintenance, the plant was restored to full power on November 14. At the end of the inspection period on December 13, plant power was steady at approximately 100%.

I. OPERATIONS

O1 Conduct of Operations

O1.1 Multiple Plant Components Found Out-of-Position

a. Inspection Scope (71707)

The inspector reviewed the licensee's reported instances of plant components found out of their expected position.

b. Observations and Findings

On December 7, 1999, the plant leadership team (PLT) observed that the number of "mis-positioning events" at Indian Point 3 in the first eleven months of 1999 was higher than the industry average. A trend DER (99-02716) was written to identify those instances where plant components were not properly configured or aligned, and to trend additional components if they were found to be out of their required position. The licensee queried the 1999 DER database by a search of DER keywords for "Valve out of Position," and "Breaker out of Position," and identified 22 instances of "out-of-position" events. Some examples included:

DER	Title
99-00572	Valve DA-6-1 [inlet isolation valve to 31 EDG air start receiver trap] shut; not positioned in accordance with EDG COL
99-00719	Blank flange found in line while performing work on valve FP-441.
99-00790	Local Fan Switch Found out of Position
99-00886	Three instances where configuration controls were not adequate within a PTO boundary.
99-01459	Valve found mispositioned.
99-02177	Valve [SWT-19-1] out of position required by a PTO.

The inspector noted that the 22 instances for 1999 did not represent a comprehensive scope of equipment configuration control problems in recent months at IP3. Additional

DERs involving mispositioned or improperly configured components did not state the keywords “out of position” in the DER. Several instances in 1999 involved broader configuration control problems where some components were not properly aligned for the plant conditions at the time. These issues were also identified individually in the DER system, and the principle deficiencies were described as procedural inadequacies, PTO process issues, or human performance errors. Some additional examples were:

99-02167 “Valve with Hold Tag Inadvertently Removed.” A valve was removed during the last refueling outage as part of a maintenance activity to replace various Target-Rock valves. The maintenance supervisor was not aware that the valve was part of a “hold-off.”

99-02254 “Inadvertent Loss of Reactor Coolant During Recirc Switch Test.” The RHR system boundary was not effectively controlled by procedure while testing during the last refueling outage.

99-02742 “32 MG Set Output Breaker has Lock on Local Trip Pushbutton.” A padlock was installed by a protective tagout (PTO) during the last refueling outage to prevent the breaker from closing during maintenance. The lock was not removed when the PTO was cleared at the end of the outage.

The licensee was also pursuing the broader configuration control issues and the human performance aspects associated with ineffective implementation of the protection tagout system. However that category of component alignment problems were not included or referenced in a similar trend DER for broader configuration control issues.

c. <u>Conclusions</u>

The NRC noted that you independently began trending an increasing number of out-of-position valves and breakers in December which we regarded as a good initiative. While this initial effort was good, the screening criteria used to identify configuration control issues was initially somewhat narrow to identify all instances for evaluation.

O1.2 Shift Turnovers and Control Room Observations

a. <u>Inspection Scope</u> (71707)

The inspectors regularly observed shift turnover evolutions in the control room, and subsequent shift turnover meetings between the off-going and on-coming operating crews. The observations were conducted during the morning shift, afternoon shift, and weekend shift turnovers.

b. Observations and Findings

The operations shift turnover process was proceduralized in Operations Directive OD-6, “Shift Relief and Turnover.” The inspectors noted good adherence to this procedure by operations personnel. Each operator performed control room panel walkdowns with his relief and identified significant plant parameters and indications that were at expected or unusual values. The turnover environment was maintained under a restriction to general control room access, and was good for clear and formal communications. On-coming control room operators performed thorough panel walkdowns, practiced formal communications, provided written turnover sheets, and communicated thorough reviews of plant status and shift orders.

Following one turnover during the inspection period, the inspector observed a nuclear plant operator (NPO) plant tour and noted that the he was knowledgeable of plant status and the objectives of his watch. The NPO was thorough in performing his tours and required duties.

c. Conclusions

The operations staff demonstrated good overall performance and good procedural adherence during shift and position turnovers. The inspectors consider the licensee’s shift turnover process to be an organizational strength. During the following plant tour, the inspector observed that operators demonstrated good knowledge of the status of plant equipment.

O7 Quality Assurance in Operations

O7.1 Response to Generic Letter 98-02

a. Inspection Scope (TI 2515/142)

The inspector reviewed NYPA’s efforts taken to determine if potential drain down paths could be created by operator or equipment error, similar to an occurrence at the Wolf Creek Nuclear Plant as discussed in Generic Letter (GL) 98-02, ”Loss of Reactor Coolant Inventory and Associated Loss of Emergency Mitigation Functions While in a Shutdown Condition.” Where susceptibility to the Wolf Creek event existed, the inspector reviewed the measures being taken by NYPA to prevent such occurrences.

b. Findings and Observations

In their letter IPN-98-123, dated November 19, 1998, NYPA concluded that the Indian Point 3 emergency core cooling systems were potentially susceptible to potential drain down paths similar to the Wolf Creek event. The inspector reviewed this response and several department memoranda that supported it. Specifically, NYPA concluded that additional precautions should be added to certain risk assessment and operations procedures to prevent an incident similar to Wolf Creek from happening at Indian Point 3. Also, licensed operators would be provided training on lessons learned from the Wolf Creek event. These improvements were intended to be done prior to the next refueling outage (RO-10).

Engineering noted that inadvertent opening of the in-series residual heat removal (RHR) suction isolation valves, AC-MOV-730 and 731, and selected safety injection (SI) valves during hot shutdown could result in an alignment comparable to the Wolf Creek event. While procedures and interlocks existed to prevent simultaneous opening of these valves, additional precautions were warranted for some procedures. The inspector verified that appropriate precautionary notes, as suggested by the operations department, were added to heatup and cooldown procedures, POP-3.3, “Plant Cooldown - Hot to Cold Shutdown” and POP-1.1, “Plant Heatup from Cold Shutdown Condition.” However, NYPA did not follow through on recommended changes by the outage management group to be included in administrative procedure AP 9.2, “Outage Risk Assessment.” These changes were also designed to prevent simultaneous opening of the RHR suction isolation valves and selected SI valves. During the current inspection, NYPA issued DER 99-02401 on October 22, 1999, to correct this procedure error. The inspector interviewed training department personnel and two licensed operators and verified that lessons learned type training concerning the Wolf Creek event was conducted prior to the recent refueling outage. However, the other department inputs (Maintenance, MOV group, Quality Assurance, Performance and Reliability) were not constructive in suggesting improvements and considering human factor aspects to prevent a Wolf Creek type of event at Indian Point 3. The inspector concluded that, given the susceptibility of Indian Point 3 to the Wolf Creek event as evidenced by the thorough engineering review of the issue, the licensee’s initial actions taken in late 1998 in response to GL 98-02 were weak and not comprehensive.

NYPA recently reviewed its initial actions taken in response to GL 98-02. In addition to DER 99-02401 noted above regarding AP-9.2, NYPA issued DER 99-02414 recognizing that enhancements, including procedure changes and a consideration of human factor aspects, were needed to ensure positive configuration control of the RCS boundary. With these DERs included in the corrective action system, the inspector concluded that NYPA’s current actions met the intent of the requested actions of GL 98-02.

c. Conclusions

NYPA’s overall response to GL 98-02 was acceptable. This included precautions added to heatup and cooldown procedures to prevent inadvertent opening of isolation valves that could result in an alignment comparable to the Wolf Creek event. However, initial actions taken in late 1998 were not comprehensive, such as a lack of consideration of human factor aspects to ensure positive configuration control of the RCS boundary. NYPA issued appropriate Deviation/Event Reports to correct this weakness and to meet the intent of the requested actions in GL 98-02.

O8.1 (Closed) LER 05000286/1999-12: A Common Condition Causing Multiple Core Exit Thermocouples to be Inoperable During Postulated Accident Conditions Due to Moisture Intrusion.

LER 05000286/1999-12 documented that ten safety-related core exit thermocouples (CETs) would be inoperable during post accident conditions due to moisture intrusion. The moisture intrusion could cause the thermocouple to fail at elevated temperatures due to steam formation inside the thermocouple sheathing. During the corrective action effectiveness review for LER 05000286/97-12 “A Common Condition Causing Multiple Core Exit Thermocouples to be Inoperable During Postulated Accident Conditions Due to Moisture Intrusion, an Original Manufacturer Defect,” the licensee tested the core exit thermocouples qualified in accordance with Regulatory Guide 1.97 for potential moisture intrusion during Refueling Outage No. 10 (RO-10). The licensee identified that ten thermocouples did not meet the established acceptance criteria for insulation resistance. The thermocouples identified were replaced with thermocouples by a different manufacturer and post-installation testing was satisfactory. All CETs qualified in accordance with Regulatory Guide 1.97 were satisfactorily tested prior to plant start up from RO-10. The inspectors conducted an in-office review of the LER and considered the LER adequately described this event and its corrective actions. No violations of NRC requirements were identified **(LER 05000286/1999-12)**.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Maintenance General Comments

a. Inspection Scope (61726, 62707, 37551)

The inspectors reviewed selected maintenance work activities and supporting work documentation. Activities were selected based on the systems, structures, or components contained within the scope of the maintenance rule.

b. Observations and Findings

The inspectors observed all or portions of the following corrective maintenance activities:

• WR 97-06119-14: Repairs for 31 Main Boiler Feed Pump High Vibration

On November 18, 1999, the licensee observed high vibrations in the 31 main boiler feed pump (MBFP) turbine casing, turning gear motor, gage board, and tubing. The inspector observed the licensee’s troubleshooting and noted that both MBFPs have experienced various high vibration problems since 1997. The licensee consulted with vendor representatives who recommended taking the pump out of service to inspect the pump-turbine shaft coupling, and to modify the turbine exhaust hood. While the pump was out of service, the licensee also checked the pump-turbine hardware at the baseplate mounting, and discovered that the fasteners had not been properly torqued during prior maintenance. The fasteners were subsequently torqued in accordance with maintenance specifications, and the pump was returned to service with normal vibration levels.

• WR 99-04304-00: Repair of Main Turbine Hydraulic Control Trip Valve Gaskets

On November 1, 1999, (approximately two weeks after startup from the last refueling outage) Siemens-Westinghouse notified the licensee that the St. Lucie nuclear plant experienced a turbine trip and reactor trip on October 29, 1999, following the failure of an oil pressure sensing diaphragm in the main turbine trip block. The trip occurred 14 days after completing a refueling outage which included replacement of all diaphragms in the trip block, and was traced to the installation of a substandard gasket in the main turbine trip oil system by a Siemens-Westinghouse work group during the outage.

The licensee performed troubleshooting with the plant at full power and observed excessive oil in the vicinity of the low bearing oil, low vacuum, and the thrust bearing differential pressure trip devices, which indicated that the diaphragms in these devices were leaking. Based on a detailed review of the material in the warehouse and the material records for the gaskets they received, NYPA concluded that a faulty gasket was installed in the main bearing oil pressure sensor.

Because the St. Lucie failure occurred soon after the gaskets were installed, NYPA began a prompt load reduction on November 3. Once the turbine was off-line, the trip oil system was opened, and the gasket for the low bearing oil trip device was inspected. Maintenance workers noted that a leak had progressed and there was a visible tear through the body of the gasket. The gasket was replaced and tested. The plant was the returned to power operations the same day. NYPA issued an Operating Events report to the industry to make other nuclear plants aware of the problem.

• WR 99-04592-00: Repairs of 36 Circulating Water Pump Discharge Pipe

On November 16, 1999, an auxiliary observed a significant leak in the 36 and 34 circulating water pumps' (CWPs) discharge piping in the plant's cooling water intake structure. The 36 CWP discharge pipe had developed on 8-12 inch circumferential crack and was leaking approximately 25-50 gallons per minute back into the river water within the intake structure. The 34 CWP pipe had a similar but smaller crack and a lower leak rate. All CWP discharge pipes are 84 inches in diameter and are normally above the river water level, but are regularly wetted by the river when its level rises during daily tidal fluctuations. The high humidity environment and the regular tidal actions caused a long term degradation of the pipes' exterior coating and corrosion of the base metal. The area around the pipe cracks had not been recently monitored by the licensee.

The inspector observed portions of the 36 CWP pipe repairs, which included rebuilding of the pipe walls with patch plates, and replacement of the exterior coating. The licensee developed a plan to inspect the remaining CWP discharge piping, and considered that a longer term permanent resolution for this condition may be warranted.

• WR 99-05031-00; Repair of 480Vac Switchgear Room Conduit Penetration Seal

During hurricane Floyd on September 17, 1999, the licensee observed water leaking into the 480Vac switchgear room through two buried conduits (1MQ4/FB and 1MP1/CB) that entered the room from a adjacent transformer yard. The conduits contained power cables for transformer auxiliaries, and did not affect safety-related cables in the switchgear room. To correct this problem, the licensee installed an expandable RTV compound to seal all of the cable conduits entering the room from an underground electrical manway (#4) in the transformer yard. The manway had been prone to flooding during storms or rises in the groundwater level and allowed water to enter into its associated electrical conduits. The licensee's repairs appeared sufficient to prevent further water intrusion into the switchgear room through the subject conduits.

• WR 99-03360-03; Replacement of 33 Service Water Pump

The 33 service water pump (SWP) was replaced on December 12, 1999, after its differential pressure entered the action range during a periodic surveillance test. The replacement work included the removal of the pump motor, check of the motor heater, pump removal, inspection of the discharge piping, installation of refurbished pump and motor, and reconnection of piping and tubing. The inspectors observed the pump removal and installation, and motor removal performed using Procedure PMP-012-SWS, "Service Water Pump Removal and Installation." Replacement work went well and the appropriate procedure adherence was observed. The licensee was reviewing the frequency of the preventative maintenance (pump and motor replacement and refurbishment) due to the performance data and history indicating some service water pumps have required replacement approximately 1-1/2 years earlier than the scheduled preventive maintenance (PM) frequency.

• WR 99-04727-00; Repair of the 80ft Containment Airlock Door Seal, and
• WR 99-04727-03, Post Work Test (PWT)

The inspector observed the 80' Containment Airlock Door Seal Repair which included removal of the worn seals, cleaning of the door surface, and installation of new seals. Applicable radiological and confined space requirement were documented in the work request, discussed in pre-job brief, and adhered to by the maintenance and health physics workers. The inspector also observed the PWT for the 80ft Containment Airlock Door Seal Repair which included a containment entry and weld channel seal leak rate test. The maintenance workers appropriately followed work pack and maintenance procedures in the completion of the PWT.

c. Conclusions

Maintenance activities observed were conducted satisfactorily and in accordance with applicable maintenance and administrative procedures. The corrective maintenance performed was satisfactory to resolve the deficient conditions and the post maintenance testing was adequate to determine the effectiveness of the repairs. The licensee appropriately monitored performance of equipment within the scope of the maintenance rule and re-evaluated preventive maintenance frequencies based on equipment performance.

M1.2 Problem Identification Description Tags Not Removed

a. Inspection Scope (71707)

The inspectors reviewed Problem Identification Description (PID) tags on panels in the control room during surveillance activities and in the emergency diesel generator rooms during system walkdowns to evaluate effects of the identified conditions on equipment testing and operation, and to determine whether the installed PIDs were consistent with the PID log.

b. Observations and Findings

The inspector reviewed approximately 50 PIDs in detail. Ten PID tags (listed in the enclosed Table below) were still hanging in the control room or on the equipment after work to correct the identified problem had already been completed and the PID closed. Closed PIDs with tags remaining in the field was identified in previous Deficiency/Event Reports (DERs 98-01375 and 99-00351) and inspection reports (1999006, Sec. E7.2, and 1999007, Sec M1.3). Resolved PID tags left hanging on equipment have caused operators and test personnel to believe that an equipment problem existed that did not, and also could prevent the identification of another similar deficiency if it should subsequently recur. Two closed PIDs observed during the current inspection period are discussed below.

- On November 24, 1999, the inspector observed control room operators investigate a 4 degree temperature swing in component cooling water (CCW) at the non-regenerative heat exchanger. In order to investigate the problem, an auxiliary operator was dispatched to temperature control valve TCV-130 (CCW outlet from the non-regenerative heat exchanger (NRHX)) to investigate a problem identified on PID (#45126) tag that was installed on the controller for TCV-130 on the main control board. On September 8, 1999, operators identified that TCV-130 had a valve binding problem that could affect automatic temperature control of CCW at the NRHX. The PID was installed on the valve controller in the control room to alert operators to this condition. After investigating the current problem, operators determined that the valve was not binding, and that it was not the cause of the CCW temperature fluctuation. The inspector noted to the operating crew that PID# 45126 had already been closed on November 19, 1999, and the tag was subsequently removed. The time operators took to investigate PID #45126 delayed their troubleshooting of the current CCW temperature swing (documented in new PID #46857). Although the safety consequences of investigating the problem identified on PID #45126 were not significant, unnecessary actions taken to troubleshoot a previously resolved problem complicated operator response to a system transient, and could challenge operators and equipment in broader transient conditions involving multiple plant systems and components.

- Emergency diesel generators (EDGs) 31, 32, 33 had PID tags installed on their control panel cabinets that documented a need to “inspect and tighten wires and screws in cabinet.” The deficiency documented in these PIDs was identified on December 31, 1997. The work to resolve these PIDs was completed on September 29, 1999, and the work request (WR) package was closed October 14, 1999. The PIDs were still installed on November 26, 1999.

Station Directive SPO-SD-01, “Work Control Process,” provided requirements on the removal of PID tags, and stated that: “<u>IF</u> the work in the field is complete, <u>THEN</u> the *individual* performing the work shall remove the associated PID tags and attached them to the work package or note their disposition in the work package.” This procedure did not explicitly require removal of PID tags after the deficiency was resolved, and did not provide guidance for removing tags for PIDs that were canceled or reassigned to other work packages. The PID removal requirements in procedure SPO-SD-01 represented a weakness in the licensee’s work control process as evidenced by numerous resolved PIDs in the field and control room. Current corrective actions to address PID removal are being tracked under DER 99-01166, “PID tags in field after work completed”; however, twelve DERs on this subject were generated in 1999.

Closed PIDs Observed In the Plant After Work Completed

PID No.	WR #	PID Description	Observed In Plant	WR Work Completed	WR Date Closed
45691	99-02945-00	LCV-1207A 31 D/G Fuel Oil Day Tank Level	11/26/99	9/8/99	10/21/99
29027	98-00200-00	DG 31 Control Panel	11/26/99	9/29/99	10/14/99
41154	98-03185-00	Small oil leak 31 EDG	11/26/99	10/7/98	11/10/98
45202	99-03399-00	During the performance of 3PT-M79B cylinder exhaust temperature on left bank cylinders #4 and #6 exceeded 1050 degrees F after 30 minutes fully loaded run time. As per 3PT-M79B this temperature condition indicates high cylinder loading	11/26/99	9/24/99	9/24/99
40332	98-03485-01	Perform diagnostic in accordance with AP-22.3 immediately after RO-10 scheduled work is completed for this equipment and as plant status allows this item is for baseline data collection purposes.	11/26/99	11/16/99	11/16/99
29029	98-00200-02	Inspect and tighten as necessary all screw wire connections located in the control cabinet of EDG33 during scheduled diesel PMS	11/26/99	9/29/99	10/14/99
43908	98-05374-00	Replace primary fuses associated with 33 EDG ega fuses FU2285, FU2286, FU2287 reference drawing 9321-F-30073	11/26/99	5/18/99	8/12/99 10/14/99
45719	N/A	Compressor shuts off @ 310#. Is less than or equal to 308#	11/26/99	rejected 11/16/99	N/A
35852	97-02463-01	D drive does not stop at BOC and TOC in auto	11/26/99	2/4/98	3/18/98
45126	99-03147-03	Air leak from between I/P and I/P air regulatory mating surface. CCR indication is that valve is not returning to the null position	11/26/99	11/12/99	11/19/99

c. Conclusions

The recurring problem with PIDs remaining in the plant and in the control room after work has been completed, rejected, or canceled represented a weakness in the licensee's work control process and caused unnecessary actions by operators to troubleshoot abnormal equipment conditions.

M1.3 Surveillance General Comments

a. Inspection Scope (61726)

The inspectors reviewed selected surveillance test activities and their supporting documentation. The activities were selected based on the systems, structures, or components contained within the scope of the maintenance rule.

b. Observations and Findings

The inspectors observed all or portions of the following surveillances:

- 3PT-M79B and WR 99-03485-01; 32 Emergency Diesel Generator Periodic Surveillance and Diagnostic Test

- 3PT-M79C and WR 99-03485-02; 33 Emergency Diesel Generator Periodic Surveillance and Diagnostic Test

- RA-11, Reactor Flux Map; Power Distribution and Hot Channel Factor Surveillance

c. Conclusions

Routine surveillance tests were conducted appropriately and in accordance with procedural and administrative requirements. Test and performance monitoring personnel maintained a good level of communication and coordination with control room operators during observed surveillance tests. Test instrumentation was within the required calibration periods and all test acceptance criteria for operability were met.

M1.4 Core Thermal Power Calculations **(URI 05000286/199900901).**

a. Inspection Scope (61706)

The inspectors reviewed the licensee's core thermal power evaluation procedure to verify that input data sources were appropriate, and that the licensee's calculations of core thermal power were correct.

b. Observations and Findings

Plant Operating Procedure (POP) 2.1, "Operation at Greater than 45% Power," establishes the requirements for steady state operation, including the daily calculation the thermal power and nuclear instrumentation system (NIS) power range channel adjustment, if required. Station Operating Procedure SOP-RPC-6, "Reactor Thermal Power Calculation," detailed the methodology for performing the thermal power calculations. While observing a licensed operator gather the required plant data and perform a thermal power calculation, the inspector verified that data was reasonable and consistent with previous data. The inspector also reviewed several of the licensee's documented core thermal power calculations, verified that the calculations were completed in accordance with procedure, and that the calculations were technically accurate by independently performed calculations for thermal power using the same data sources as the licensee. That calculation yielded 99.61% power and the licensee's equivalent calculation yielded 99.71%

The inspectors noted that SOP-RPC-6 listed the preferred and alternate sources of the steam generator pressure data as the Critical Functions Monitoring System (CFMS), i.e., "the plant computer." The licensee considered the CFMS to be an operator aid and did not maintain it as Quality Assurance (QA) Category I equipment. However, the licensee did not provide a formal basis for the use of a non-qualified instrument (i.e., plant computer) to verify compliance with the Technical Specification limit on core thermal power.

The inspectors reviewed the procedures that calibrated the steam generator pressure from the pressure transmitter through the Qualified Safety Parameter Display System (QSPDS) into the CFMS.

- Calibration procedure 3PC-R18A "Steam Line Pressure Transmitter Check and Calibration" checks and calibrates the steam line pressure transmitters - the point where the pressure indication is read.

  The inspectors verified that Procedure 3PC-R18A had been completed during Refueling Outage 10 and that the pressure transmitters were within as-found tolerance (±3.7 mVdc).

- Test procedure 3PT-R154E “QSPDS ‘N’ Chassis Calibration” and Procedure 3PT-R15F “QSPDS ‘N’ Chassis Signal Isolation Calibration” check and calibrate the input signal into the QSPDS, which feeds the CFMS for the steam generator pressure data. The inspector verified that all tests performed under procedures 3PT-R154E and 3PT15F were within tolerance specifications.

- Calibration procedure CSD-CP-3, “[Computer Products Incorporated] C.P.I Multiplexor Calibration” defined the requirements for operability of the CFMS analog input devices. The completed procedure indicated satisfactory results.

c. Conclusions

Independent calculations by the inspectors confirmed that the licensee’s core thermal power calculations were technically accurate based on the data inputs that were used. However, the licensee did not provide a formal basis for the use of a non-qualified instrument (i.e., plant computer) in order to verify compliance with the Technical Specification limit on core thermal power. This item will remain unresolved pending further NRC review of the licensee’s basis for its use in meeting Technical Specification requirements **(URI 05000286/199900901).**

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Cycle-11 Core Reactivity Management

a. Inspection Scope (71707)

Following the plant startup from refueling outage number 10 (RO-10), the inspectors observed several anomalies related to core reactivity parameters, including unanticipated reactor coolant average temperature (Tave) changes in response to a blended makeup to the reactor coolant system (RCS) (occurred on October 30, 1999 and November 9, 1999); inaccurate reactivity calculations during a planned down power (on November 3, 1999); and various CFMS plant computer discrepancies including: 1) indication of percent (%) power different from the nuclear instrumentation; 2) the CFMS computer indicated thermal power above the technical specification limit (3025 Megawatts - thermal); and 3) the CFMS computer indicated alert and alarm levels for the quadrant power tilt.

b. Observations and Findings

Unanticipated Changes in Average RCS Temperature (Tave)

On two separate occasions, the operators experienced an unanticipated response of Tave following a blended boron makeup to the RCS. The first unanticipated Tave response occurred on October 30, 1999 while attempting to maintain Tave within $\pm$0.1°F of Tref (RCS reference temperature). The operators initiated a boron injection of 1 gallon which resulted in a slight increase (0.2°F) in Tave. A total of 5 gallons boric acid and 6 steps of control rod insertion were needed to reduce Tave to within $\pm$0.1°F of Tref. On November 9, 1999, the second unanticipated Tave response occurred during a routine blended makeup to the RCS which caused Tave to increase slightly (approximately 0.1°F). Two borations were required to offset the increase in Tave. The licensee's investigation of these instances (DERs 99-02471 and 99-02524) revealed a non-conservative assumption in the development of the Critical Boron Concentration vs. Burnup figures, Graphs CVCS-1A and CVCS-1B. These figures did not properly account for water weight in blended makeups and thus underestimated the amount of boron in the makeup.

Operators took appropriate actions in response to the minor Tave increases. No power or significant temperature transients resulted and the operators were able to maintain Tave within Technical Specification Limits. The figures for the Critical Boron Concentration vs. Burnup, CVCS-1A and CVCS-1B in the Graphs Book were appropriately updated.

Inaccurate Tables in Operation Procedures

During a planned power reduction on November 3,1999, the operators noted that the core was not responding as expected based on reactivity calculations from the paragraph 3.1 table in Attachment 6 of plant operating procedure POP-2.1, and graph RV-3D, "Xenon Reactivity Addition vs Shutdown Rate." The reactivity calculations were off significantly from the "Beacon" computer printout provided by reactor engineering. The licensee determined that reactor engineering had not updated the paragraph 3.1 table and graph RV-3D to reflect the Cycle 11 core. Reactor engineering considered that the relatively short duration (approximately 40 days) of RO-10 was a contributing factor to the failure to update these tables. Information regarding the new core was received from Westinghouse toward the end of the outage and had not been fully incorporated into plant procedures. In the past, longer refueling outages provided sufficient time to update plant operating procedures. Reactor engineering acknowledged that completing shorter refueling outages did not negate the need for timely updates to plant operating procedures and documented the failure to update the tables in DER 99-02496, "Reactivity Calculations."

Plant Computer Discrepancies

During the plant startup from RO-10, reactor engineering and instrumentation and controls (I&C) performed a core flux map at 50% power. The data from the flux map was used to determine the full power zero axial offset detector currents which, in turn, was used to calculate the quadrant power tilt ratio for the upper and lower nuclear instrument (NI) detectors. After the reactor stabilized at full power, the full power zero axial offset detector currents calculated using the core flux from 50% power overestimated the quadrant power tilt and caused the control room annunciators for quadrant power tilt to intermittently alarm (tilt >1.75%). Also, the plant computer indicated an alert value for the quadrant power tilt (>1.3%) and to intermittently alarm (>1.75%). Even though a full core flux map had been complete at 100% power, reactor engineering did not update the full power zero axial offset detector currents. The licensee elected to defer updating the detector currents until the next scheduled surveillance (approximately 4 weeks), and permitted the intermittent quadrant power tilt control room annunciator alarms to persist, pending the next surveillance.

During the later part of November 1999, the critical functions monitoring system (CFMS) was indicating up to 1% higher power than the power range NI channels and displayed core thermal power greater than 3400MW (vs. The TS limit of 3025MW). The licensee's investigation found that the Leading Edge Flow Meter (LEFM), which detects and displays feedwater flow had a higher output voltage than the previous operating cycle, and the NI output voltage to the plant computer appeared to be higher than the previous cycle. This discrepancy was documented in DER 99-02649, "Plant Computer Indication of %Power Different from NIS."

The licensee did not regard inaccurate data reported by the CFMS plant computer to be a safety concern and stated that the CFMS was considered an operator aid, and not a basis for plant operation at 100% power. However, the CFMS produced a control room annunciator alarm for quadrant power tilt, and CFMS data was used in the reactor thermal power calculation to verify compliance with Technical Specifications (see Section O1.2).

c. Conclusions

Reactor engineering was slow to update reactivity tables in operating procedures and the full power zero axial offset detector currents in the plant computer after the plant achieved full power following the last refueling outage. The use of outdated tables and incorrect detector currents resulted in unanticipated core temperature responses following blended boron additions to the reactor coolant system, and during a plant power reduction. Operators took appropriate actions in response to minor Tave increases and the unexpected core responses. No power or significant temperature transients resulted and the operators were able to maintain maximum Tave below the Technical Specification limit of 547°F.

E2.2 NYPA's Evaluation of the Reactor Trip at Indian Point 2 on August 31, 1999

a. Inspection Scope (37551)

On August 31, 1999, the Indian Point 2 (IP2) plant experienced a reactor trip. The complications that accompanied the reactor trip resulted in a NRC Augmented Inspection Team (AIT) inspection. The New York Power Authority (NYPA) reviewed the IP2 reactor trip complications for applicability to Indian Point 3 (IP3). The purpose of this inspection was to evaluate the results of NYPA's review.

b. Observations and Findings

The licensee's evaluation of the IP2 event was included in an internal document, No. IP3-SSZ-99-12, dated October 12, 1999, "Evaluation of August 31, 1999 Plant Trip at Indian Point 2 for Issues That May be Applicable to IP3." The document addressed all major issues in the IP2 trip, including, inability to reset the blackout logic; inability to connect the outside power to the emergency bus; degraded grid voltage relay setting with the station auxiliary transformer automatic load tap changer in the manual mode; trip set point and testing of the emergency diesel generator (EDG) output breakers; setting of the load sequencing timers; and, alternate power supplies for the station batteries and instrument buses.

The inspector's review of the above document determined that, for each issue, the licensee had evaluated the IP2 condition and described its applicability or non-applicability to IP3. The inspector also found that, in general, the licensee had done an acceptable review of the issues and, whenever necessary, had initiated a DER to further review and/or correct potential concerns. For instance, regarding the transformer load tap changer, NYPA considered its operation in the manual mode to be an operator workaround with high priority resolution. Nonetheless, to ensure that adequate controls existed when an IP3 transformer tap changer was placed in the manual mode, the licensee initiated DER 99-01856 to further evaluate the issue and identify required corrective actions. Four actions resulted in this case, including one to improve the procedural requirements for placing the tap changer in manual.

The inspector reviewed selected DERs and confirmed that the planned actions were reasonable. The inspector also verified that the statements made by the licensee regarding the design and operation of the electrical system were correct and that the surveillances of the safety related electrical components were acceptable. The verification included the review of the control circuits of appropriate medium and low voltage circuit breakers. The inspector also reviewed the procedures for the surveillance of the transformer tap changer, the degraded grid voltage relays and associated timers, and for the testing of the low voltage circuit breaker trip devices.

Except as described in section E2.2, below, regarding the degraded grid relay setting, the inspector identified no areas of concern with the design, operation and maintenance of the electrical system.

c. Conclusions

The licensee conducted an acceptable review of the August 31, 1999, Indian Point 2 reactor trip complications for the purpose of assessing what actions, if any, should be taken to prevent a similar at Indian Point 3 (IP3); and had initiated appropriate actions to ensure that IP3 would not be vulnerable to a similar event

E2.3 Degraded Grid Relay Settings **(URI 05000286/199900902)**

a. Inspection Scope (37551)

The inspector reviewed applicable calculations, the surveillance procedure, and selected design and licensing documents to evaluate the adequacy of the degraded grid voltage relays set points.

b. Observations and Findings

Electrical System Description

During normal plant operation, power for the plant loads comes from two transformers. The unit auxiliary transformer (UAT) takes its input from the main generator and supplies four of the six-6.9 kV buses. The other two 6.9 kV buses are supplied by the Buchanan 138.kV Substation (offsite power) through the station auxiliary transformer (SAT). In the event of a unit trip, an automatic fast transfer switches the plant loads from the UAT to the SAT. The UAT and SAT are equipped with an automatic load tap changer to maintain the 6.9 kV bus voltage at the desired level, under changing grid voltage and plant loads.

The engineered safeguards equipment is powered by four-480 Volt buses, 2A, 3A, 5A, and 6A. During normal plant operation, buses 2A and 3A are supplied from the 6.9 kV unit auxiliary (onsite) power (buses 2 and 3, respectively); buses 5A and 6A are supplied from the 6.9 kV station auxiliary (offsite) power (buses 5 and 6, respectively). Buses 2 and 3 are automatically transferred to the offsite source in the event of a unit trip.

In the event of a loss of offsite power or degraded voltage conditions, buses 5A and 6A are powered by EDGs 33 and 32, respectively. Buses 2A and 3A are automatically tied together and, then powered by EDG 31. Loss of voltage and degraded voltage conditions are measured on each of the four 480-Volt buses. A loss of voltage or sustained degraded voltage condition on any one bus initiates the start of the associated EDG and the transfer of the bus loads to the EDG without affecting the other buses.

Relay Set Point Basis

On August 31, 1984, the licensee submitted a Technical Specification (TS) change request to the NRC regarding the operation and the setting of the degraded grid voltage (DGV) relays and timers. Specifically, in their letter IPN-84-35, the licensee proposed that the DGV relays be set to actuate at "≥414 Vac." This voltage corresponded to 90% of the voltage rating (460 Volts) of some motors for engineered safeguards equipment. In the associated safety evaluation, the licensee stated that the DGV relay set point is based on the limiting safety-related load and conservatively accounts for voltage losses associated with the cable feeders from the 480-volt buses to the MCC's [Motor Control Centers]."

On October 31, 1984, in response to NRC questions regarding the ability of the motor starters to pickup and start the loads during minimum grid voltage and maximum load conditions, the licensee submitted a document titled "480-volt Motor Starter Voltage Analysis for Transient Voltage Conditions." In that document, submitted with their response letter (IPN-84-49), the licensee addressed the relay set points again (page C-8) and stated that the TS limit of 414 volts was based on the IP3 MCC motor starters which "have a manufacturer-specified guaranteed pickup voltage of 408 volts."

With 414 Volts at the 480 V buses, the licensee recognized that some motors potentially could receive a terminal running voltage below the recommended 90% of the motor voltage rating, but justified its acceptability on the basis that the voltage difference was small (7 Volts maximum), that the condition would be temporary, and that the resulting thermal degradation would be minimal. The NRC found the licensee's evaluation acceptable and granted the TS change (Safety Evaluation Report dated April 9, 1985). Accordingly, Table 3.51 of the current IP3 TS established the 480 Volt bus degraded voltage relay set point allowable value to be ≥414 Vac for ≤10 seconds, if coincident with a safety injection (SI) actuation signal, and for ≤ 45 seconds without an SI actuation signal.

Voltage Drop Calculation Results

The degraded grid voltage study that supported the TS change described above was issued on October 29, 1984. The study involved an evaluation of the plant voltage profile under various grid and load conditions. Although the study included the results of only ten cases, the evaluation apparently addressed at least 70 different plant conditions. The study also contained the results of voltage verification tests performed by the licensee.

Based on the results of Case 31 and Case 70, the study preparer recommended that the undervoltage trip level of all relays be set at 422 volts. Apparently, the recommendation was to assure a minimum of 414 V (90% of rated voltage) at the terminals of Containment Spray Pump 31 (considered to be the most limiting component). Case 31 assumed the Buchanan 138 kV bus to be at 136 kV; a loss of coolant accident (LOCA) with all safeguard loads on the offsite source; a fast transfer of the loads from the UAT to the SAT; and a frozen load tap changer. Case 70 was not included in Appendix A of the study. The DGV relays are currently set at 422 V ± 2 V, apparently in accordance with the above recommendation. However, the licensee was not able to provide a calculation or other document to confirm the acceptability or the origin of this set point.

Following the original voltage study, the licensee issued two more calculations, one on March 13, 1992, Document No. SS4-10, Revision 1, “1991 Update of IP3 Degraded Grid Voltage Studies,” and one on August 24, 1998, Calculation No. IP3-CALC-EL-01972, Revision 0, “1997 Update of IP3 Degraded Grid Voltage Studies.” Under Case 31, both calculations predicted lower voltages at the loads. However, if set point recommendations of the first calculation had been applied to the subsequent calculations, the relay trip level of 422 Volts on the 480 Volt buses would have been essentially the same. Specifically, the inspector’s review of these calculations showed that the recommendation would have been the same in the 1992 calculation and 424 Volts in the 1998 study. No specific set point evaluation or recommendation was discussed in the 1992 and 1998 calculations.

Regarding the basis for the TS amendment, i.e., bus voltage required to ensure 408 Volts at the motor starters, the inspector determined that, as early as in the 1984 calculation, Case 31 predicted voltage drops in excess of the 6 Volt used in the TS amendment request. Specifically, the inspector observed that the voltage drops between bus 5A and MCC 36A and between bus 6A and MCC 36B were 7 volts and 8 volts, respectively. Therefore, the 414 Volts minimum stated in the TS amendment would not assure that, under the postulated conditions, the motor starters received the minimum rated voltage (as specified by the licensee in their October 31, 1984, letter to the NRC). For the same study case, the 1998 calculation predicted the voltage drop between Bus 5A and MCC 36A to be 9 Volts.

<u>Required DGV Relay Settings</u>

To correctly set the actuation point of the DGV relay, a voltage profile under limiting conditions should first be calculated. Once the limiting component is identified, the difference between the required and the calculated voltage should be added to the calculated bus voltage. The setting of the relays should then be calculated, taking into consideration the accuracy of the sensing circuit.

In each of the three voltage drop calculations the licensee calculated the voltage drop from the 480 Volt bus to the MCC bus, but they did not address the voltage drop from the MCC bus to the motor starter coil. This additional voltage drop can be assumed to be minimal (close to zero) only if the motor starter control wiring remains within the confines of the MCC. In many cases, however, the control wiring travels to different areas of the plant and/or the control room. In these cases, the voltage drop cannot be assumed to be insignificant. The licensee should have calculated the maximum voltage drop from the MCC bus to the motor starters and added it to the voltage drop between the 480 Volt bus and the MCC.

Regarding the accuracy of the sensing circuit, the licensee did not perform a calculation to account for the components ability to correctly translate the bus voltage signal to the output of the relays (error), the drift and repeatability of the components, and the ability of the technicians to correctly set the relays. This calculation is required for the proper setting of the relays.
Based on the above, the inspector concluded that the licensee’s controls to ensure the adequacy of the electrical design were insufficient in that the calculated voltage drop between the 480 Volt buses and the MCCs was greater than that assumed in the TS

amendment, causing the minimum voltage specified by the TS at the 480 Volt buses to be lower than required. Several opportunities were missed by the licensee to verify the adequacy of and correct the TS voltage requirements. The inspector also concluded that minimum required voltage at the 480 Volt buses and the setting of the DGV relays cannot be defined until the licensee has calculated the voltage drop from the MCC bus to the motor starter coils and the accuracy of the voltage sensing circuit. This issue is unresolved pending completion of such calculations by the licensee and review by the NRC **(URI 05000286/1999000902)**.

Licensee's Evaluation

The inspector discussed the finding with the licensee who immediately initiated DER 99-02465 and an operability determination. The licensee's evaluation concluded that reasonable confidence existed to consider the system operable. The licensee's bases for the conclusion included: (1) the 1984 test results that showed the motor starters picking up at less than 80% (384 Volts) of their rated voltage; (2) the voltage drop calculation that conservatively assumed maximum LOCA loading, frozen SAT tap changer, and grid voltage below the maintained minimum level; (3) the response procedure for a low voltage alarm set at 448.8 Vac that directs the operator to monitor the bus voltage and take appropriate actions; and (4) the emergency operating procedures that direct the operator to verify the status of the safeguards equipment and take the required actions to correct any anomalies.

The inspector reviewed the above documents and other bases described by the licensee in their operability determination. Sufficient assurance existed to consider the electrical system operable pending the licensee's calculation of the minimum required bus voltage and the correct setting of the DGV relays.

c. Conclusions

The licensee justified the operability of the electrical system under normal operating conditions. However, several opportunities were missed in the past to verify the adequacy of and correct the TS specified minimum voltage at the 480 Volt buses. The missed opportunities were the result of inadequate reviews of licensee or contractor prepared calculations. The issue regarding the minimum required voltage at the 480 Volt buses and the required relay settings are unresolved pending the licensee's calculations to address the voltage drop from the motor control center to the motor starter coils and the accuracy of the voltage sensing circuit **(URI 05000286/19990901).**

E2.4 System Engineering Review of EDG Deficiencies

a. Inspection Scope (93802)

The inspectors conducted interviews and performed a field walkdown of the major components and selected portions of Emergency Diesel Generators (EDG) system with the system engineer. The discussions included system health, deficiencies and planned maintenance.

b. Observations and Findings

During walkdowns of the emergency diesel generators (EDG), the inspectors did not identify any equipment deficiencies which had not been previously identified and appropriately documented on a PID tag. The PID tags observed in the field were verified against the Reliable Online Maintenance Environment (ROME) data base and the work request data base to ensure that corrective actions were being adequately tracked, and work activities planned to resolve the identified deficiencies. The inspectors noted, however, there were numerous PIDs hanging on EDG equipment even though the PID had been resolved (resolved PIDs still in the field are discussed in Section O2.1). The plant equipment appeared to be properly maintained and in good working condition. The system engineer was knowledgeable of the issues affecting the system.

c. Conclusions

The overall material condition of the EDGs was good. The EDG equipment appeared to be properly maintained and in adequate working condition. The system engineer was knowledgeable of the equipment condition, problems, and maintenance associated with the EDGs.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Inspection Follow-up Item (IFI) 0500286/19988001, “Incorporate EPRI PPM results into Design Calculations.”

By letter dated January 22, 1998, the licensee committed to revise the thrust/torque calculations for the applicable valves to incorporate the Electric Power Research Institute (EPRI) Performance Prediction Methodology (PPM) thrust predictions by December 11, 1998. This inspection follow-up item documented the need to verify completion of this commitment. The inspectors reviewed select design-basis thrust calculations and verified that current calculations utilized the PPM for minimum thrust requirement as necessary. Therefore, this inspection follow-up item is closed **(IFI 05000286/988001).**

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Rainwater Leakage into the Primary Auxiliary Building and Spread of Contamination

a. Inspection Scope (71750)

The inspector reviewed the licensee's analysis and actions following an inleakage of a significant amount of rainwater into the primary auxiliary building and a subsequent spread of contamination inside the pipe penetration at the 41 foot elevation.

b. Observations and Findings

During a rain storm on November 27, 1999, several hundred gallons of rain water entered into the primary auxiliary building (PAB). Two areas outside the PAB had flooded after their storm drains became clogged with debris (windblown trash, pigeon feathers, etc.). One area at the 41 foot elevation accumulated over 4 feet of water in a narrow crevice area between the PAB and the containment structure, and water entered the PAB through a construction joint in a concrete wall. Another area at the 80 foot elevation (containment purge valve area) accumulated water deep enough to flow under an exterior door at that level. The relative negative pressure maintained in the PAB contributed to a large accumulation of water inside the building that flowed into a controlled surface contamination area on the 41 foot elevation. However, the water then flowed into an uncontrolled clean area and spread contamination from the controlled area.

The licensee initiated DER 99-02655 to document this incident. Radwaste personnel removed the accumulated water from the PAB, and cleaned the contamination in the uncontrolled areas of the 41 foot elevation. Maintenance personnel also injected a sealant into the construction joint. The inspector walked down the PAB areas affected by this incident with a radwaste technician involved with the cleanup. The extent of the spread contamination was not significant; however, the licensee did not have a process to regularly monitor the subject areas outside the PAB for water accumulation or storm drain blockage. In response to the DER, the licensee established a weekly inspection of the drain pipe outside exterior door at the 80 foot elevation, and provided for a six month activity to clean out the storm drain outside the 41 foot elevation. The inspector questioned the basis for the six month frequency, since that area was known to accumulate large amounts of windblown debris. Upon further review, the licensee elected to inspect the area every three months and to require a cleanout of the drain pipe at least every six months.

c. Conclusions

The licensee's actions were effective in removing a large volume of rain water that leaked into the primary auxiliary building (PAB), and to cleanup the resulting spread of contamination into an uncontrolled area. The causes of the storm drain blockage were satisfactorily addressed by establishing a regular scheduled activity to inspect and cleanout storm drains outside the PAB.

X1 Exit Meeting Summary

Findings were discussed periodically with the licensee throughout the course of the inspection. The operations specialist inspector presented results of the TI 2515/142 review to NYPA management on October 29, 1999 and summarize the preliminary inspection findings. The licensee acknowledged the preliminary findings and conclusions, with no exceptions taken. On December 21, 1999, the resident inspectors presented the integrated results for the entire inspection period. The licensee acknowledged the findings presented, and did not identify any materials examined during the inspection that were considered proprietary.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

R. Barrett	Site Executive Officer
R. Burroni	I&C Manager
J. Comiotes	General Manager-Operations
F. Dacimo	Plant Manager
J. DeRoy	Director, IP-3 Engineering
R. Deschamps	Health Physics - General Supervisor
L. Lee	System Engineer
D. Mayer	General Manager-Support Services
S. Munoz	Assistant System Engineering Manager
T. Orlando	Performance Reliability Supervisor
K. Peters	Licensing Manager
J. Perrotta	Quality Assurance Manager
R. Robenstein	Operations Support Manager
J. Russell	General Manager-Maintenance

INSPECTION PROCEDURES USED

IP 37551:	On-site Engineering
IP 38703:	Commercial Grade Dedication
IP 40500	Corrective Action Program
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Event Reports
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

URI 05000286/199900901	No formal basis for the use of a non-qualified instrument (i.e., plant computer) in order to verify compliance with the Technical Specification limit on core thermal power. This item will remain unresolved pending further NRC review of the licensee's basis
URI 05000286/199900902	Degraded Grid Voltage relays, and 480Vac bus voltage calculations did not include actual voltage drop values for accurate calculations to determine bus voltage and relay settings.

<u>Closed</u>

LER 1999-012	A Common Condition Causing Multiple Core Exit Thermocouples to be Inoperable During Postulated Accident Conditions Due to Moisture Intrusion
IFI 05000286/19988001	Incorporate EPRI Performance Prediction Methodology into MOV Design Calculations

LIST OF ACRONYMS USED

AIT	Augmented Inspection Team
AP	Administrative Procedure
CFMS	Critical Functions Monitoring System (Plant Computer)
CFR	Code of Federal Regulations
DER	Deficiency/Event Report
DGV	Degraded Grid Voltage
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
GL	Generic Letter
HP	Health Physics
I&C	instrumentation and controls
IFI	Inspection Follow-up Item
IP2	Indian Point Nuclear Power Plant Unit 2
IP3	Indian Point Nuclear Power Plant Unit 3
kV	kilo-Volt
LEFM	leading edge flow meter
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MCC	Motor Control Center
MOV	motor-operated valve
MW_t	MegaWatts - thermal
NCV	Non-cited Violation
NPO	Nuclear Plant Operator
NRC	Nuclear Regulatory Commission
NYPA	New York Power Authority
OD	Operations Directive
OD	Operability Determination
ONOP	off-normal operating procedure
PDR	Public Document Room
PID	Problem Identification Description
PWT	Post-Work Test
PM	preventive maintenance
QA	Quality Assurance
QSPDS	Qualified Safety Parameter Display System
RCA	Radiologically Controlled Area
RCS	reactor coolant system

RHR	Residual Heat Removal
RO	Refueling Outage
ROME	Reliable Online Maintenance Environment
RP&C	Radiological Protection and Chemistry
SAT	Station Auxiliary Transformer
SG	steam generator
SI	safety injection
Tave	Reactor Coolant System Average Temperature
TCV	Temperature Control Valve
TI	Temporary Instruction
Tref	Reactor Coolant System Reference Temperature
TS	Technical Specification
UAT	Unit Auxiliary Transformer
URI	Unresolved Item
Vac	Volts - alternating current
WR	work request