April 25, 2003

MEMORANDUM TO: Chairman Diaz

FROM: Hubert T. Bell
Inspector General **/RA/**

SUBJECT: NRC ENFORCEMENT OF REGULATORY REQUIREMENTS AND COMMITMENTS AT INDIAN POINT, UNIT 2 (CASE NO. 01-01S)

Attached is an Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC) Event Inquiry that addresses the NRC's oversight of operations at the Indian Point, Unit 2 nuclear power plant in Buchanan, New York.

Please call me if you have any questions regarding this Event Inquiry. This report is furnished for whatever action you deem appropriate. Please notify this office within 90 days of what action, if any, you take based on the results of the Event Inquiry.

Attachment: As stated

cc w/attachment:
Commissioner Dicus
Commissioner McGaffigan
Commissioner Merrifield
W. Travers, EDO

April 25, 2003

MEMORANDUM TO: Chairman Diaz

FROM: Hubert T. Bell **/RA/**
Inspector General

SUBJECT: NRC ENFORCEMENT OF REGULATORY REQUIREMENTS AND COMMITMENTS AT INDIAN POINT, UNIT 2 (CASE NO. 01-01S)

Attached is an Office of the Inspector General (OIG), U.S. Nuclear Regulatory Commission (NRC) Event Inquiry that addresses the NRC's oversight of operations at the Indian Point, Unit 2 nuclear power plant in Buchanan, New York.

Please call me if you have any questions regarding this Event Inquiry. This report is furnished for whatever action you deem appropriate. Please notify this office within 90 days of what action, if any, you take based on the results of the Event Inquiry.

Attachment: As stated

cc w/attachment:
Commissioner Dicus
Commissioner McGaffigan
Commissioner Merrifield
W. Travers, EDO

Distribution:(Linda's C:\ORPCheckout\FileNET\ML031200172.wpd)

Case File 01-01S Historical File AIGI r/f, memo only HBell, memo only

BCC:
OPA (5 copies)
OCA (5 copies)
SECY
NRC PDR
B. Dwyer
G. Mulley
R. Bucci

ADAMS Accession No.: ML031200172

OIG	OIG	OIG	OIG	OIG
R.Bucci **(VOB)**	G.Mulley **(GAM)**	B.Dwyer **(BCD)**	D.Lee **(DCL)**	H.Bell **(HTB)**
04/ **25** /03	04/ **24** /03	04/ **25** /03	04/ **25** /03	04/ **25** /03

Official File Copy

OFFICE OF THE INSPECTOR GENERAL
EVENT INQUIRY

NRC ENFORCEMENT OF REGULATORY REQUIREMENTS AND COMMITMENTS AT INDIAN POINT, UNIT 2

Case No. 01-01S

/RA/
Veronica O. Bucci, Special Agent

/RA/
George A. Mulley, Jr.,
Senior Level Assistant for Investigative Operations

/RA/
Brian C. Dwyer
Assistant Inspector General for Investigations

NRC ENFORCEMENT OF REGULATORY REQUIREMENTS AND COMMITMENTS AT INDIAN POINT, UNIT 2

Case No. 01-01S April 25, 2003

TABLE OF CONTENTS

BASIS AND SCOPE

The Office of the Inspector General (OIG) initiated this inquiry in response to a Congressional request that OIG examine issues concerning U.S. Nuclear Regulatory Commission (NRC) oversight of operations at the Indian Point 2 (IP2) nuclear power facility in Buchanan, New York. The request referred specifically to "internal Con Ed/Indian Point 2 condition reports" made public in a January 2001 petition review board meeting that "may include information which indicates that the plant operator may be in violation of a commitment made back in 1997 regarding design bases requirements."

The Congressional request also focused on issues raised by an engineering consultant hired by the licensee who had recently resigned his position due to a differing professional opinion regarding the plant's Reactor Protection System. The request noted that one of the more lengthy condition reports cited discrepancies between design drawings and the as-built configuration of the Reactor Protection System.

Based on the above concerns, OIG initiated an Event Inquiry to examine:

> I. NRC's oversight of IP2's progress toward fulfilling two design bases commitments made to the NRC in 1997. These commitments were made in response to NRC's 1996 request for information concerning plant programs and processes for controlling and maintaining operations within the facility's design bases.
>
> II. NRC's response to the specific concerns raised by an IP2 engineering consultant pertaining to discrepancies between design drawings and the as-built configuration of the Reactor Protection System.
>
> III. NRC's oversight of IP2's corrective action program between 1995 and 2001.
>
> IV. NRC's utilization of its Senior Management Meeting process to heighten attention to IP2.

BACKGROUND

NRC's Regulation of Power Plants — Overview of Terms Used in This Report

Nuclear power plants are required to adhere to U.S. Nuclear Regulatory Commission (NRC) regulations to ensure their safe operation. These regulations include requirements that power plants operate in accordance with their current license, which includes (1) the plant's technical specifications, (2) license conditions, (3) licensee commitments made in response to NRC Generic Letters and Bulletins, and (4) the Final Safety Analysis Report (FSAR).[1] Design bases information identifies the specific functions to be performed by a power plant's structures, systems, and components as well as associated design parameters.

In addition, plants are required to have a corrective action program (CAP) that enables them to identify, prioritize, and correct problems in a timely manner. Power plants manage their CAP by maintaining a database of action items, or condition reports, which describe particular plant conditions in need of repair or attention. Plants typically prioritize these condition reports based on safety significance and address them accordingly.

NRC provides oversight of nuclear power plants to ensure that plants are operating safely. The agency conducts reactor inspections to determine whether power plants are in compliance with agency requirements. Inspections range from routine, baseline inspections[2] to inspections beyond the baseline which may focus on areas of declining plant performance. The agency issues sanctions (i.e., enforcement actions) — such as Notices of Violation (NOV),[3] fines, or orders to modify, suspend, or revoke licenses — when plants are out of compliance. In 2000, NRC implemented a Reactor Oversight Process (ROP), which was intended to be substantially different from the previous oversight process and to take into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and evaluating the safety performance of NRC-licensed plants. Under this process, inspection findings are evaluated for risk significance using pre-established criteria. Plants that fail to meet certain safety objectives, as determined by performance indicators and inspection findings, are to receive increased inspection activity, focusing on areas of declining performance and may be subject to enforcement action.

---

[1]The FSAR is a licensing document that provides a description and safety analysis of the site, the design, design bases and operational limits, normal and emergency operation, potential accidents, predicted consequences of such accidents, and the means proposed to prevent or mitigate the consequences of such accidents. When the FSAR has been updated, it is referred to as the updated FSAR, or UFSAR.

[2]Baseline inspections are common to all nuclear power plants; NRC's baseline inspection program is the normal inspection program performed at all nuclear power plants. The program focuses on plant activities that are "risk significant," that is, those activities and systems that have a potential to trigger an accident, can mitigate the effects of an accident, or increase the consequences of a possible accident.

[3]An NOV formalizes a violation by identifying a requirement and how it was violated.

Between 1986 and 2001, NRC also used its semiannual Senior Managers Meetings (SMM)[4] as a means to increase attention to plants with persistent operational problems. During these meetings, the agency's senior managers reviewed certain plants experiencing declines in performance. Participants decided whether to increase oversight of subject plants and, if so, by what means. For example, a SMM decision might require a plant to undergo additional inspections, or the staff could issue a "trending letter" to advise a licensee that NRC had taken note of declining plant performance, or designate the plant as in need of heightened NRC attention (e.g., designation as an Agency Focus Plant).

One way in which nuclear power plants fulfill NRC expectations is through regulatory commitments. Regulatory commitments are non-binding statements made by licensees to NRC indicating they will take specific actions, for example, to verify the accuracy of UFSAR information, and they typically reflect the means by which licensees will accomplish the commitment (e.g., in a certain timeframe, following a specific approach).

The Indian Point Nuclear Power Plant, Unit 2 (IP2), is one of two operating pressurized water reactors located in Buchanan, NY, 24 miles north of New York City. IP2 began commercial operations in August 1974. The Consolidated Edison Company of New York, Inc. (ConEd), owned IP2 until September 6, 2001, when the plant was purchased by Entergy Nuclear Operations, Inc. NRC's Region I office[5] provides oversight for IP2.

---

[4]The Senior Management Meeting (SMM) program which required semiannual meetings of NRC senior managers was replaced in 2001 by the Agency Action Review Meeting (AARM) program. The AARM is an annual meeting of NRC senior managers under the Reactor Oversight Process. This meeting essentially replaces the SMM under NRC's previous oversight process.

[5]NRC has four regional offices that conduct inspections of nuclear reactors within regional boundaries. NRC's Region I provides regulatory oversight for IP2 and other nuclear facilities within the northeast region of the United States.

DETAILS

I. NRC OVERSIGHT OF IP2'S PROGRESS TOWARD FULFILLING TWO 1997 DESIGN BASES COMMITMENTS

Overview of Design Bases

Nuclear power plants are designed so that internal and external events (e.g., loss of coolant accident, fire, earthquake) will not jeopardize plant safety or threaten the health and safety of the public. A plant's design bases in part describe how the plant will cope with various accidents and emergencies. Plant structures, systems, and components (SSC) must be built in accordance with design requirements that will enable the plant to meet its design bases and, consequently, to withstand such accidents and emergencies. Plant operators are expected to not make plant modifications to safety related systems without having performed NRC required safety analyses, which are needed to prove the modification will not affect the plant's ability to meet its design bases requirements. Furthermore, when modifications are made, they are supposed to be reflected in the plant's design bases documents, which link each plant SSC to its design bases and original design requirements. Design bases documents include such information as industry, regulatory, and manufacturer criteria for plant systems and information generally contained in the UFSAR specifying system functions and requirements, component functions and requirements, interface requirements from supporting and supported systems, applicable accident analysis assumptions related to the systems, and plant design drawings and calculations.

NRC Requests Licensee Feedback on Design Bases Issues

NRC team inspections during 1995 and 1996 identified concerns regarding the ability of NRC licensees to maintain and implement the design bases at certain plants. To learn more about the scope and extent of the problems among operating nuclear power reactors, the staff proposed that all licensees be required to provide information regarding the availability and adequacy of design bases information. To that end, on October 9, 1996, NRC issued a letter to each NRC reactor licensee in accordance with Title 10, Part 50, Section 54(f), Code of Federal Regulations (10 CFR 50.54(f)) requesting that each licensee submit under oath a written response within 120 days describing and discussing the effectiveness of its programs and processes for controlling and maintaining operations within the facility's design bases. The stated purpose of the letter was "to require information that will provide the U.S. Nuclear Regulatory Commission (NRC) added confidence and assurance that [licensee plants] are operated and maintained within the design bases and any deviations are reconciled in a timely manner."

Specifically, NRC found it problematic that some licensees had failed to (1) appropriately maintain or adhere to plant design bases, (2) appropriately maintain or adhere to the plant licensing basis, (3) comply with the terms and conditions of licenses and NRC regulations, and (4) assure that the UFSARs properly reflect the facilities. According to the letter, "The extent of the licensees' failures to maintain control and to identify and correct the failures in a timely manner is of concern because of the potential impact on public health and safety should safety systems not respond to challenges from off-normal and accident conditions."

NRC Reviews Overall Response

Subsequent to NRC's receipt and review of all licensee responses to the October 9, 1996, letter, the staff issued SECY-97-160,[6] which described a four-phased approach which NRC had undertaken to review the licensee responses to the 10 CFR 50.54(f) request. The SECY described the completion of the first three phases and concluded that all licensees had established programs and procedures to maintain the design bases of their facilities. However, SECY-97-160 also recommended certain plant-specific, final-phase followup activities to address the staff's concerns about either (1) the performance of certain licensees in controlling facility design bases or (2) the need to validate the effectiveness of a particular element of a licensee's design control program.

A manager in the NRC's Office of Nuclear Reactor Regulation (NRR) told OIG that the request began with a high level of agency concern that there were widespread problems pertaining to the accuracy of plant UFSARs and there was a heightened awareness that these problems needed to be resolved as quickly as possible. However, as licensee efforts to address these concerns unfolded, NRC staff recognized that this effort was more resource intensive than had initially been anticipated, and staff allowed licensees to have more time to complete these efforts.

IP2 Responds to NRC Design Bases Request

In response to NRC's October 1996 10 CFR 50.54(f) request to ConEd regarding IP2, the licensee made two specific commitments. In its February 13, 1997, letter that conveyed these commitments to NRC, ConEd stated its intent "to voluntarily initiate and complete" an UFSAR review program. The program was scheduled for completion within 24 months. The UFSAR review program was to include (1) verification of the accuracy of the UFSAR design bases information, (2) assessment to confirm that the UFSAR design bases information was properly reflected in plant operation, maintenance, and test procedures, (3) review of the UFSAR to identify and resolve any internal disagreements or inconsistencies which could impact the design bases, and (4) development of a process to enhance overall the UFSAR accessibility. In its second commitment, ConEd stated it would continue its "Design Basis Document (DBD) Initiative" to review and update existing design bases documents and create new ones if needed. The continuation of the DBD Initiative was to include supplementation of 22 DBDs with a combination of additional DBDs and added information on interfacing systems. This effort was also to be completed in 24 months.

IP2 Extends Completion Date

In a letter dated February 17, 1999 (24 months after the initial commitments were made), ConEd provided an update to NRC concerning the commitments it had made pursuant to NRC's 1996 request. The letter reported that both the UFSAR verification effort and DBD initiative were underway; the UFSAR effort was approximately 65 percent complete and the

---

[6] SECY 97-160, "Staff Review of Licensee Responses to the 10 CFR 50.54(f) Request Regarding the Adequacy and Availability of Design Bases Information," dated July 24, 1997.

supplementation of 6 of 27 DBDs was in progress. The letter also changed the completion date of both commitments: December 31, 1999, for the former and December 31, 2002, for the latter.

OIG learned that NRC is not expected to formally approve changes in commitment completion dates such as the one described above. According to the NRR manager, commitments are often schedule or process related (e.g., licensee commitment to fix something by a specific time or in a particular manner) and changes in completion dates are not necessarily problematic. For example, the manager said, a rule may say to fix something in a timely manner and the licensee will commit to do so within 2 months. However, if the licensee fails to make the 2-month deadline, the licensee may adjust the timeframe to another date that NRC would consider timely.

The NRR manager and Region I staff told OIG that after IP2 became involved in these efforts, all parties realized that the 2-year timeframe that ConEd initially committed to was unrealistic. A number of plants, including IP2, required additional time to complete their review and NRC staff generally viewed these extensions as reasonable.

OIG also learned that with regard to ConEd's schedule change for the UFSAR commitment, Region I staff felt IP2's progress toward fulfilling the commitment was proceeding in a timely manner and that the schedule change was reasonable.

In June 2000, ConEd provided NRC with a new projected completion date of March 31, 2001, for its commitment to verify the accuracy of the UFSAR, and ConEd reported that it still anticipated completing its DBD initiative by December 31, 2002.

On December 31, 2002, Entergy forwarded correspondence to NRC modifying the completion date for the original commitment that was due on December 31, 2002, to a revised commitment date of December 31, 2003. According to the Region I Administrator and staff, the modification of the completion date was reasonable and acceptable. The Region I Administrator said he considered these deferrals to be appropriate given that numerous, more significant operational and design-related issues emerged over this period requiring extensive licensee management attention and resources.

Region I Oversees IP2 Progress in Fulfilling Design Bases Commitments

According to a Region I Branch Chief, he visited IP2 on April 3, 2001, and verified for himself that the UFSAR update was "essentially done" and that ConEd was "just wrapping up loose ends." The Branch Chief drew this conclusion based on a presentation ConEd gave him describing the methodology for and status of the UFSAR effort. Additionally, he stated that his conclusion was supported by a series of NRC inspections conducted at IP2 since the initial commitment that confirmed progress was being made. OIG reviewed NRC inspection reports from October 1997 through August 2002 and found that some of the NRC inspections specifically looked at the UFSAR and DBD efforts through baseline and special inspections. These reports reflected inspectors' observations that progress continued to be made in these efforts.

The Branch Chief also explained to OIG that when Entergy took over as the licensee for IP2 in September 2001, it assumed ConEd's commitment to complete its DBD Initiative by December 31, 2002, without modifying the completion date. Entergy incorporated the commitment into its "Fundamentals and Improvement Plan" for IP2. With regard to the status of the DBD commitment, the Branch Chief said he visited the plant in May 2002 at which time the plant had completed the review of 22 of the 27 DBDs and planned to complete 3 more by the end of 2002.

According to NRC Inspection Report No. 05-247/2002-010, dated August 28, 2002, which reported results of a supplemental and problem identification and resolution (PI & R) inspection from June 17 through July 19, 2002, Entergy had revised its schedule for completing the DBD effort. According to the inspection report, two remaining DBDs (fire protection and electrical separation) would be completed in 2003, rather than by December 2002. The inspection team concluded that the schedule modification was reasonable.

OIG FINDING

In February 1997, ConEd responded to NRC's 10 CFR 50.54(f) request for information by committing to two separate 24-month efforts at IP2. In the first of these two commitments to NRC, ConEd stated its intent to initiate and complete an UFSAR review program and in its second commitment, ConEd stated it would continue its IP2 DBD Initiative to review and update existing design basis documents and create new ones if needed. Although ConEd initially committed to complete both efforts in 2 years, ConEd revised its projected completion dates two times for the first effort. The UFSAR review program, initially expected to be completed by February 1999, was extended to December 1999, and finally completed by April 2001. The completion date for the second effort was also revised twice, once by ConEd and the second time by Entergy Nuclear Operations, Inc., IP2's current license holder. The DBD Initiative, initially slated for completion by February 1999, was extended to December 2002, and is now expected to be finished by December 31, 2003. OIG found that the NRC staff did not object to the time extensions because it believed each extension was reasonable, given other significant operational problems at the plant, the effort that was required to fulfill the commitments, and the licensee's steady, but slow, progress in addressing them.

II. NRC'S RESPONSE TO REPORTED DISCREPANCIES BETWEEN RPS DESIGN DRAWINGS AND AS-BUILT CONFIGURATION

The Reactor Protection System

The Reactor Protection System (RPS), a system described by NRC staff as "very safety significant" to nuclear power plant operations, is designed to detect a problem in the plant and, if the problem is serious enough, cause the plant to trip (i.e., to automatically shut down in an emergency situation). According to NRC staff, the system can be manually or automatically activated to initiate a plant shutdown. Staff said that to ensure that the reactor will shut down when necessary, the RPS features multiple, independent equipment and components. Any individual RPS component, therefore, could be significant. Furthermore, RPS interfaces with many other safety systems for process monitoring of safety parameters such as reactor coolant pressure, temperature and flow, pressurizer level, steam generator level, and reactor building pressure. As a result, staff said, deficiencies in other systems could have an effect on RPS's ability to operate during an event.

The Region I Administrator told OIG it is a significant problem if the as-built configuration of a system, such as the RPS, is inconsistent with what is needed for the system to be functional. He said it is of lesser significance, but still important, when a system's as-built configuration is inconsistent with design drawings but is still functional. He explained that in either case, inconsistencies between system configurations and design drawings may be indicators that other issues within the system warrant attention.

IP2 Condition Reports Identify Design Bases Discrepancies

OIG learned that in February 2001, a ConEd engineering consultant raised an allegation to Region I pertaining to design bases discrepancies between design drawings and the as-built configuration of the RPS. The allegation referred to 13 IP2 condition reports (CR) that IP2 plant personnel, including the engineering consultant, had written to describe these issues. These CRs were a subset of a larger number (more than 300) of CRs written on RPS between 1998 and 2001.[7] This subset of CRs identified circumstances in which the system's wiring violated statements in the UFSAR. For example, the CRs identified instances of wires associated with computer and alarm circuits being in close proximity of and sometimes in the same cable tray as the wires associated with the trip and logic circuits. The CR reported that these as-built wiring configurations were in conflict with UFSAR wiring separation criteria.

OIG reviewed summaries of the 13 CRs raised in the allegation. Eight of the 13 (CRs 199803574, 199902835, 199903445, 199904968, 200007597, 200009499, 200009641, 200010125) focused on:

- Quality assurance requirements for design verifications,
- Wiring changes resulting from modifications that could not be located, and
- Wiring configurations not in accordance with UFSAR separation requirements.

---

[7] As context, both regional staff and the IP2 engineering consultant told OIG that roughly 10,000 CRs were being written per year during this timeframe concerning IP2 conditions perceived by licensee staff as in need of attention.

A ninth condition report (CR 200100327) summarized the eight preceding CRs. The remaining four condition reports (CRs 199900478, 199902274, 200008415, and 200008818) documented additional examples of related RPS wiring discrepancies. (See Appendix A for a listing of the 13 CRs and a description of the issues covered in each.)

The engineering consultant told OIG that while employed at IP2 he wrote CR 200100327 as a summary after becoming aware of the eight earlier CRs. These eight CRs summarized documented deficiencies such as wiring separation issues, wiring configurations not in accordance with design drawings, and cable splices not identified on drawings.

The engineering consultant told OIG that he was concerned that collectively these issues warranted a higher level of attention than ConEd had determined was appropriate and that he had raised the matter with ConEd management. Specifically, he explained, he wanted ConEd to perform another Operability Determination (OD) on the RPS to determine whether the system in its current configuration was operable. He told OIG that prior to his writing of CR 200100327, ConEd performed an OD (OD 00-018) on RPS that addressed a subset of the issues raised in CR 200100327. However, he explained that in his opinion that OD did not go far enough to assess the functional changes that may have resulted from the as-found wiring conditions. Dissatisfied with ConEd's response to the issues he raised, and concerned that ConEd would downgrade CR 200100327 from Significance Level (SL) 2 to an SL3,[8] the engineering consultant formally raised the matter to Region I as an allegation.

NRC's Response to RPS Design Bases Discrepancies

OIG reviewed documentation of NRC's response to the issues raised by the engineering consultant and learned that NRC:

(1) inspected several RPS deficiencies prior to the engineering consultant's allegation,

(2) conducted an inspection focused specifically on the RPS wiring discrepancies described in CR 200100327, and

(3) responded directly, in writing, to the engineering consultant on the outcome of NRC's review of the concerns he raised in his allegation.

In the following three sections, OIG describes each of these efforts, which OIG learned, collectively addressed each of the 13 CRs mentioned in the engineering consultant's allegation.

(1) NRC Inspects RPS Deficiencies

OIG learned that prior to receipt of the allegation from the ConEd engineering consultant, and during the course of escalated regulatory activities by Region I subsequent to a steam

[8]IP2 CRs were ranked on a scale of 1 through 4, with SL1 assigned the highest level of significance. The engineering consultant explained to OIG that CRs assigned a higher SL would receive a more heightened response from ConEd. For example, CRs assigned as SL2 were required to receive a formal Operability Determination, while this was not a requirement for CRs assigned as SL3.

generator tube rupture that occurred at IP2 in February 2000,[9] a team of Region I inspectors conducted a 7-week inspection of "engineering, operations and maintenance, radiation protection, security, and weld radiographs associated with the steam generator replacement project." Inspection activities included a review of a sample of RPS open corrective action items relating to the RPS's nonconformance with design drawings and the UFSAR.

OIG reviewed the inspection report findings pertaining to the RPS review. The inspection report (IR 05-247/2000-014), dated January 2001, described the RPS issue as follows:

> The issue involved the licensee's observation that wiring within the protection racks did not always conform with the statements contained in the UFSAR and electrical separation criteria contained in drawing A208685. Specifically, the licensee found instances of wires associated with computer and alarm circuits being in close proximity of, and sometimes in the same cable tray as, the wires associated with the trip and logic circuits. The licensee also identified examples of switch contacts originally reserved for logic and trip function being used for computer and alarm functions. All potential interactions involved a single train of protection logic and low energy and low voltage circuits.

According to the NRC inspection report, the inspector reviewed three CRs mentioned in the engineering consultant's allegation (CRs 200007597, 200008818, and 200009499) related to RPS logic rack wiring separation concerns, OD 00-018 (dated November 28, 2000), and OD supporting documentation. Based on this review, the report concluded, "There were no significant findings associated with this issue."

The Region I inspector who conducted the review told OIG that the inspection was focused on ensuring that the discrepant conditions reported in the three CRs did not affect the safe operation of the RPS. Although the inspector acknowledged to OIG that it was better to review all open issues and CRs related to a particular system and to sample closed CRs, the inspector explained that he did not do so because of the limited scope of the review coupled with limited manpower resources and time. The Region I Administrator explained to OIG that this sampling of RPS issues was part of a larger review of deficiencies and corrective actions that needed to be addressed at the plant.

(2) NRC Inspects RPS Wiring Discrepancy Issues Described in CR 200100327

OIG learned that following the engineering consultant's allegation pertaining to the RPS, NRC inspectors revisited the issues that the consultant had collectively recorded in CR 200100327 and documented their findings in a June 2001 inspection report (IR 05-247/2001-005) which described the Region I inspectors' review of:

> Corrective actions taken by ConEd to address issues raised in CR 200100327;

[9] On February 15, 2000, IP2 experienced a steam generator tube rupture in one of the plant's four steam generators, which resulted in a minor radiological discharge to the atmosphere.

ConEd's February 12, 2001, OD 01-002, "Ensuring the Functional Capability of a System (RPS) or Component," to determine whether the bases used in the OD were valid and accurate;

Safety Evaluation 99-160-EV to change the UFSAR such that wire separation between safety and non-safety wires was no longer required; and

RPS open condition reports.

These inspection efforts are described below.

Corrective Actions Taken to Address CR 200100327 Issues

OIG reviewed IR 05-247/2001-005, which described Region I's examination of the licensee's corrective actions associated with CR 200100327 and the eight feeder CRs, and corrective actions pertaining to CR 200008415 and one additional CR not referenced in the allegation. The inspection report indicated that as background for the inspection, NRC reviewed CRs 199900478 and 199902274, which had been referenced in the allegation. According to the inspection report, inspectors also:

- ♦ Reviewed a ConEd evaluation titled, "SL-2 Evaluation for CR 200100327 on the Reactor Protection System," dated March 7, 2001, to confirm that this evaluation addressed appropriate root causes, contributing causes, compensatory actions and the proposed corrective actions.

- ♦ Attended a Corrective Action Review Board (CARB) meeting which reviewed and discussed the evaluation.

- ♦ Reviewed the list of ICA (Implementation of Corrective Actions) for CR 200100327 to confirm that the listed corrective actions adequately addressed the root causes and the concerns raised in CR 200100327.

- ♦ Reviewed a sample of corrective actions and issues to determine whether these corrective actions were timely and appropriate to address the issues.

- ♦ Reviewed the rationale provided for delayed corrective actions.

- ♦ Reviewed IP2 documents to confirm that on February 12, 2001, ConEd had generated OD 01-002, "Ensuring the Functional Capability of a System (RPS) or Component," to demonstrate that the RPS can perform its safety function, in spite of the combined wiring and documentation deficiencies.

- ♦ Reviewed IP2 documents to confirm that on March 12, 2001, ConEd completed a safety evaluation to address the wiring separation issue regarding RPS wiring configuration conformance with the UFSAR.

Based on this review, the inspectors found no issues that would render the RPS incapable of performing its intended safety function. Specifically, the inspection report stated that no findings of significance were identified.

ConEd's Operability Determination (OD) 01-002, "Ensuring the Functional Capability of a System (RPS) or Component"

According to IR 50-247/2001-005, ConEd generated OD 01-002 "to demonstrate that the RPS could perform its safety function." OIG learned that Region I inspectors reviewed OD 01-002 to determine whether the bases used in the determination were valid and accurate. The inspectors also reviewed supporting documents used in the OD to verify that the data and bases were accurately translated. Supporting documents reviewed included RPS test procedures and test results, a modification for replacing 88 relays in the RPS, and a sample of CRs associated with RPS wiring issues. CRs reviewed included CR 200008818 and two additional CRs not mentioned by the alleger. Based on their review of this issue, the Region I inspectors again concluded that there were "no findings of significance."

Safety Evaluation 99-160-EV

Inspection report 50-247/2001-005 noted that in March 2001, ConEd generated a safety evaluation (SE 99-160-EV) to change the UFSAR so that wire separation between safety and non-safety wires would no longer be required and "safety and non-safety wires can run together within a panduit inside the RPS cabinet." However, according to the Region I inspectors, the safety evaluation did not provide sufficient rationale to justify the change to the UFSAR. According to the inspection report, this matter was not resolved during the inspection and was referred to NRR for review. OIG learned that the results of NRR's review were documented in IR 50-247/2001-010, dated December 17, 2001. In that inspection report, NRR acknowledged that SE 99-160-EV failed to address certain relevant issues; however, NRR concluded that the wiring separation between safety and non-safety wires inside the RPS cabinets was not a design requirement for IP2 and was in compliance with industry standards. Consequently, the wiring configuration at IP2 met design requirements and the issue was closed.

RPS Open Condition Reports

As part of this inspection effort, inspectors also reviewed the RPS condition report history since 1998 and found that since that time more than 300 CRs had been written on the RPS. As of March 9, 2001, 47 CRs remained open in the database, some for almost 3 years. ConEd's records indicated that of the 47 CRs, 3 were ranked as SL4; 37 were ranked as SL3; and 7 were ranked as SL2. The inspection report stated that in response to the inspectors' concerns about possible combined operability or functional effects from the 47 open CRs, ConEd performed an overall assessment of the 47 open CRs and concluded that no functional problems existed. The inspectors reviewed a sample of four CRs to confirm that there were no combined effects that could challenge the functionality of the RPS. The selected CRs were, based on the inspectors' judgement, most likely to yield inspection findings. Based on this review, the inspectors again identified no findings of significance.

(3) Region I Response to Engineering Consultant's Allegation

In a letter dated July 19, 2001, Region I formally responded to the ConEd engineering consultant who wrote CR 200100327 and who subsequently raised the RPS-related issues to Region I. The letter summarized the consultant's RPS-related concerns as presented in CR 200100327, relayed NRC's inspection findings (from IR 50-247/2001-005) pertaining to these concerns, and described the licensee's actions to address them. In its letter to the engineering consultant, Region I addressed the consultant's concern that "there is a lack of response effort and inadequate corrective actions in response to concerns [the consultant] raised regarding deficiencies in the design record and configuration control of the Reactor Protection System (RPS)." The Region I letter also addressed the consultant's concern that OD 00-018 "adequately addressed RPS wire separation and isolation issues, but not the broader concerns" (i.e., loss of design control due to wiring configurations). The letter explained that in response to these concerns, NRC completed an inspection of RPS wiring issues at IP2 on May 4, 2001, that was documented in IR 50-247/2001-005.

The letter also explained that to address the "broader issue for the RPS wiring," ConEd completed an RPS operability determination (OD 01-002) on February 12, 2001, completed a root cause evaluation for CR 200100327, entitled, "SL-2 Evaluation for CR 200100327 on the Reactor Protection System," on March 7, 2001, and established a corrective action program to address other broader aspects of the RPS wiring deficiencies.

In its conclusion to the consultant's concern about RPS configuration control/design record deficiencies, the letter stated,

> . . . your concern was partially substantiated. There were design control weaknesses at IP-2. However, at the time of our inspection, ConEd had established a corrective action plan to address the broader issue as described above [i.e., loss of design control]. Further, our inspection did not uncover any issues that would render the RPS incapable of performing its intended safety function.

The letter also addressed the consultant's concern that CR 200100327, initially assigned an SL of 2, would be reassigned an SL of 3 and that, as a result, ConEd would not conduct an OD "or otherwise address the broader operability issue raised by the lack of quality control in the changes made to the RPS." The letter explained that (1) the licensee did, in fact, complete an OD for the RPS (OD 01-002), which "addressed some important wiring issues;" (2) NRC's inspection did not identify any issues that would affect the functionality of the RPS; and (3) CR 200100327 remained as an SL2 CR.

The Region I inspectors responsible for reviewing the concerns identified by the engineering consultant told OIG that they did not find anything that would render the RPS inoperable.

<u>OIG FINDING</u>

Beginning as early as 1998, ConEd identified problems associated with the IP2 RPS wiring configurations and generated internal CRs to document the findings. These CRs identified circumstances in which the system's wiring violated statements in the UFSAR. Thirteen CRs identifying (or reiterating) such wiring discrepancies were presented formally to the NRC as an allegation by an IP2 engineering consultant who was concerned that collectively the RPS wiring discrepancies warranted a higher level of attention than the licensee had determined was appropriate. OIG learned that Region I performed two inspections relative to these issues and the NRC's Office of Nuclear Reactor Regulation documented its review in a third inspection report. In addition, Region I responded directly to the engineering consultant in a letter dated July 19, 2001. OIG determined that the NRC appropriately responded to the allegations presented to Region I by the engineering consultant. OIG's review of the three inspection reports and Region I's response to the engineering consultant determined that while NRC validated some of the issues the consultant had raised, the agency repeatedly concluded there were no "findings of significance" related to the RPS wiring issues and that ConEd had appropriate measures in place to address the conditions.

III. NRC REGULATORY OVERSIGHT OF IP2'S CAP: 1995 – 2001

Overview of IP2 Operational Problems

Between 1995 and 2001, IP2 experienced a series of operational problems, attributed in part to deficiencies in IP2's corrective action program (CAP) (i.e., its program to self-identify and resolve plant problems). For example,

- In 1995, plant personnel cleaned a turbine using grit. The grit caused significant damage to the internal components of a heater drain tank pump and migrated unchecked throughout the feedwater system, surfacing 2 years later and causing valves to operate erratically.

- NRC inspections conducted between 1996 and 1997 identified various issues, including weaknesses in corrective actions taken to address problems identified by the plant. As a result, in May 1997, NRC issued an NOV citing IP2 for nine violations of NRC requirements, six of which were attributed to corrective action violations.

- In the fall of 1997, IP2 voluntarily shut down to address a large backlog of equipment, programmatic, and performance problems. The plant remained out of service until September 1998.

- In 1998, in NRC Evaluation Team Report 05-247/1998-005, NRC noted that IP2 had identified problems with its CAP in that its corrective action processes were cumbersome and inefficient, many corrective actions were untimely, and completed actions were typically not revisited to determine whether they had achieved their goal.

- In August 1999, IP2 experienced a significant reactor trip, or shutdown, partly due to weaknesses in its CAP.

- In February 2000, IP2 experienced a steam generator tube rupture, also partly attributed to weaknesses in the plant's CAP.

- In May 2000, NRC categorized IP2 as an Agency Focus Plant, a status that denotes a need for increased oversight by NRC.

- In 2001, NRC found that IP2 continued to experience problems in its CAP, including issues pertaining to its RPS.

Significance of the Corrective Action Program

NRC inspects many aspects of nuclear power plants to ensure their safe operation, including the licensees' ability to identify and correct conditions that may affect plant performance and safety. Title 10 of the Code of Federal Regulations, Chapter 50 (10 CFR 50), Appendix B, directs licensees to have a program to assess problems in plant operations and to ensure that timely and effective corrective actions take place. Therefore, it is the licensee's responsibility to implement a program to identify and resolve problems at its facility. Historically this has been referred to as the nuclear power plant's CAP.

NRC Region I staff told OIG that overall plant performance is greatly determined by the effectiveness of a licensee's CAP. Staff told OIG that they expect licensees to be aggressive in identifying concerns and appropriately correcting problems, but they recognize that every plant has problems that need to be addressed. When a CAP is effective, staff said, a licensee is able to identify, prioritize, and quickly resolve conditions that may have a negative impact on plant operations. Staff said they have found that the better performing plants are very aggressive at correcting deficiencies. These plants are also proactive in conducting preventive maintenance and in monitoring plant equipment and conditions. As a result, staff said, those licensees have more durable solutions to their problems than poorer performing plants.

Several staff members interviewed by OIG observed a direct connection between ineffective CAPs and NRC's identification of a plant as an NRC Watch List[10] Plant. According to one staff member, in every case where a plant had problems or became an NRC Watch List Plant, there was a corresponding weakness in the licensee's ability to identify, evaluate, and correct problems, as well as a weakness in assessing the effectiveness of their corrective actions.

The Region I staff told OIG that if NRC lost confidence in a licensee's CAP, the agency would seriously consider whether the licensee should be permitted to operate.

NRC Identifies Repeated Problems With IP2 CAP

OIG was told by the Region I Administrator and staff that between 1995 and 2001, NRC dedicated significant resources to conduct inspections, document findings, and issue sanctions at IP2, yet problems persisted at the plant. Many of the inspections identified problems with IP2's CAP; however, despite heightened levels of NRC attention to these weaknesses, problems related to corrective actions remained unresolved. [See Appendix B for a chronology detailing the significant inspection activity and other oversight efforts performed at IP2 by NRC during this period.]

According to Region I staff, between April 1995 and February 2001, NRC conducted 20 special team inspections at IP2, logging 5,870 inspection hours dedicated to engineering and problem identification and resolution (PI&R).[11] By comparison, the average number of hours devoted to these types of inspections at other single unit[12] Region I nuclear power plants during the same period was 3,854. Furthermore, between 1995 and 2001, IP2 received 13 enforcement actions, 9 of which identified corrective action issues and 8 of which resulted in monetary fines. [See Appendix C for additional information on these 13 enforcement actions.] This expenditure of inspection resources at IP2 was NRC's response to a perceived downward performance trend

---

[10]In 1999, there was a change in NRC terminology; Watch List plants are now referred to as Agency Focus Plants.

[11]NRC now refers to the CAP as problem identification and resolution (PI&R). This Event Inquiry, which covers a time period during which the term used to describe the process changed, refers to the process as CAP.

[12]According to a Region I Branch Chief, the term "single unit" generally refers to a nuclear power plant site with only one operating reactor inside the protected area fence. Although there are two operating units at the Indian Point site (IP2 and IP3), Region I treats IP2 as a single unit site due to its past regulatory performance problems. This results in the allocation of more inspection resources at IP2 than would be the case if the plant were treated as a dual-unit site.

that was occurring during the 1995–1999 time frame. According to NRC Region I staff, between 1995 and 2000, overall IP2 performance was not considered very good. Staff said that during that time period, IP2 had problems related to the plant's CAP.

Region I staff told OIG that it viewed 1995 as a downward turning point for the plant and recalled the grit intrusion event that occurred that year as an example of this decline. Between October 1996 and April 1997, NRC staff conducted four inspections of IP2, which resulted in the issuance of an NOV in May 1997 based on nine violations of NRC requirements. The inspections included an Integrated Performance Assessment Process (IPAP) and three routine inspections conducted by the NRC resident inspectors. Problems identified during the inspections included weaknesses in IP2's design control which, staff explained, pertained to the availability and completeness of design bases information and problems with the CAP.

The Region I Administrator told OIG that following February 1997 there was a series of events that occurred at IP2, coupled with NRC's inspection findings, that reinforced his concerns about IP2's declining performance. He told OIG that the NRC subsequently sent a message to ConEd management by issuing fairly significant civil penalties and a confirmatory action letter (CAL).[13] Additionally, he met with ConEd's Chief Executive Officer to address NRC's concerns about IP2's declining performance, the decline in overall effectiveness of management oversight, and a perception that management tolerated problems rather than aggressively identifying and correcting them.

Consequently, ConEd management responded to Region I by documenting actions it planned to take to arrest the performance declines and to improve the quality of these activities. These detailed action plans were included in a program that ConEd identified as the *Strategic Improvement Program*.

Declining Systematic Assessment of Licensee Performance Scores

According to the Region I Administrator and Region I staff, the Region's concerns about IP2's performance in 1996 were documented in NRC's Systematic Assessment of Licensee Performance (SALP) scores and periodic SALP reports for IP2. The SALP was an NRC evaluation of plant performance conducted every 12 to 24 months within the parameters of NRC's inspection program. The report included a numerical rating of the plant in four categories — plant operations, maintenance, engineering, and plant support — as well as a narrative discussion of performance in each area.

In the SALP report covering the period from September 17, 1995, through February 15, 1997, Region I staff noted that overall performance at IP2 declined. Performance in the areas of operations and plant support were rated as generally effective and some elements were very good; however, performance declined in maintenance and substantively declined in engineering. The SALP report noted many equipment problems were due to the poor condition

[13] CALs are letters issued by NRC to licensees or vendors to emphasize and confirm a licensee's or vendor's agreement to take certain actions in response to specific issues.

of a number of systems. Licensee management was involved in many plant activities and made operational decisions, but management oversight was at times ineffective regarding overall efforts to identify, evaluate, and correct problems.

IP2 Shuts Down To Address Backlog of Problems

OIG learned that following repetitive failures of safety-related electrical breakers, IP2 voluntarily shut down to address a large backlog of equipment, programmatic, and performance problems. This outage lasted from October 1997 until September 1998. According to NRC staff, IP2 used this period to try to better identify and correct these deficient conditions at the plant.

Instead of conducting a planned Operational Safety Team Inspection (OSTI)[14] of IP2, NRC permitted ConEd to hire a team of independent experts to conduct an Independent Safety Assessment (ISA) of the power plant in the spring of 1998. NRC assembled a special NRC Evaluation Team (NET) to gauge the validity and effectiveness of the ISA and review the outcome. The NET observed and evaluated the IP2 ISA from March 30 through May 7, 1998, to assess the validity of the ISA conclusions and to determine whether the ISA had fulfilled NRC's intent to obtain an OSTI-type performance assessment. According to the NET report, the ISA achieved noteworthy insights, including the identification of problems with IP2's CAP. Specifically, the ISA found that the CAP was cumbersome and inefficient, many corrective actions were untimely, and completed actions were typically not revisited to see whether they had achieved their intended impact. According to an NRC staff member who participated in the review, IP2's CAP "was not working very well at all."

Subsequent to the ISA findings, ConEd developed plans to improve station performance and, according to the regional staff and inspection reports, IP2's performance began slowly to improve following plant startup in September 1998. According to the NRC staff, inspection reports, and other docketed correspondence between NRC and ConEd, substantial changes were made to IP2's CAP during this period. However, although progress was made, a number of problems remained that required continued licensee management attention.

IP2 Experiences Two Significant Events

In August 1999, IP2 experienced a reactor trip, or shutdown, a risk-significant event that NRC staff characterized as preventable and partly attributable to weaknesses in IP2's CAP. The reactor trip was caused partly by a condition involving repetitive problems with one channel of RPS's over-temperature/delta-temperature circuitry. The condition, which existed since January 1999, had not been promptly identified, the cause of the condition had not been determined, and corrective actions had not been taken. According to the Region I Administrator, while the August 1999 event challenged safe operation, safety margins were maintained at an acceptable level.

---

[14]At the time, OSTIs were conducted to supplement normal inspections for special purposes such as to verify that a plant operator has properly prepared the staff and the plant for resumption of power operations after an extended shutdown. These inspections were performed by either a headquarters or regional team and typically consist of a 2-week onsite inspection conducted by a team of seven inspectors and a team leader.

In February 2000, IP2 experienced yet another significant problem attributed to weaknesses in IP2's CAP: a steam generator tube ruptured in one of its four steam generators, resulting in a leak that allowed pressurized radioactive water, which acts to cool the reactor, to mix with non-radioactive water in the steam generator. The power plant was manually shut down following the event. This resulted in a minor radiological discharge to the atmosphere.

CAP Problems Persist at IP2

In an NRC inspection report (IR 05-247/2001-002) issued in 2001, the Region I inspection team again noted weaknesses in IP2's CAP. According to the report, IP2's progress to effect change continued to be slow. The report "noted problems similar to those that have been previously identified at the IP2 facility, including those in the areas of design control, human and equipment performance, PI&R, and emergency preparedness."

When interviewed by OIG, Region I staff attributed IP2's CAP problems to a large backlog of problems — any one of which might not appear significant. Staff said that IP2 was able to identify problems but was frequently ineffective at prioritizing and correcting them and determining their root cause. Staff attributed this specifically to a cultural problem at IP2 that was not recognized by ConEd management until after the August 1999 event. Staff described this culture as one in which ConEd management did not emphasize or encourage staff efforts to prioritize the correction of problems and identify root causes.

The Region I Administrator and staff acknowledged that the improvements at IP2 were slow, and in some respects limited, but steady. The Region I Administrator told OIG that IP2 met NRC's minimum regulatory requirements and there was never a situation where the margins of safety had been reduced to a point where the plant was unsafe. He added that as a regulator one has to work within the regulatory framework and distinguish between conditions that are unsafe and conditions that involve weaknesses in performance. The Region I Administrator and staff repeatedly emphasized to OIG that the increased inspections and aggressive oversight never identified a situation where IP2 was unsafe.

The Region I Administrator explained to OIG that IP2's rate of improvement above fundamental protection of public health and safety is determined by the plant management. The licensee determines the type and amount of resources that it will apply to facilitate improved performance. The licensee also makes personnel selections at the plant and it is ultimately up to the individuals hired to make these improvements and effect change. The Region I Administrator told OIG that he continually pressed ConEd management to strengthen the margins of safety at IP2 by conducting numerous inspections and special assessments and by communicating the Region's findings to ConEd in a clear and direct manner.

<u>OIG FINDING</u>

Between 1995 and 2001, IP2 experienced a series of operational problems, attributed in large part to deficiencies in IP2's CAP. OIG found that during this period, Region I dedicated significant resources to conduct inspections, document findings, and issue sanctions, yet problems persisted at the plant. Between April 1995 and February 2001, NRC conducted 20 special team inspections at IP2, logging 5,870 inspection hours dedicated to engineering and problem identification and resolution. Furthermore, between 1995 and 2001, Region I issued 13 enforcement actions to IP2. Many of the inspections identified problems with IP2's CAP. However, despite heightened levels of NRC attention to these weaknesses, problems at IP2 remained unresolved. OIG found that in spite of the intensified regulatory oversight by Region I, IP2 was only able to achieve limited improvement in plant performance.

IV. NRC'S UTILIZATION OF THE SMM PROCESS TO HEIGHTEN ATTENTION AT IP2

Senior Management Meeting Process

Between 1986 and 2001, NRC held Senior Management Meetings (SMM) semiannually to allow NRC senior managers to focus agency attention on those plants of highest concern and to monitor licensee efforts to recognize and resolve performance problems. According to the March 1997 version of NRC Management Directive (MD) 8.14, "Senior Management Meeting (SMM)," the primary goal of an SMM was to identify declining trends in the operational safety of individual plants so that early corrective actions could be implemented. OIG was told by senior NRC managers that the SMM offered a means to communicate NRC's concerns to licensees with poor or adverse performance trends.

During the SMM, the senior NRC managers could opt not to take action regarding a particular plant or they could choose to take one of several actions to heighten oversight. For example, senior managers could choose to issue a Trending Letter to advise a licensee that NRC had taken notice of declining plant performance and that if performance did not improve, the plant might be placed on the NRC's Watch List. Or, the managers could choose to place a plant directly on the Watch List. A plant placed on the Watch List received increased oversight from NRC in the form of additional inspections, letters expressing agency concerns about declining performance, and other types of regulatory attention. According to the NRC staff, designation as a Watch List plant could also bring significant public attention to a licensee and could result in a negative economic impact for the utility. These potential negative consequences would motivate a licensee to improve plant performance.

Senior Management Meetings were chaired by the NRC Executive Director for Operations. Participants typically included the Deputy Executive Director for Regulatory Programs; Deputy Executive Director for Regulatory Effectiveness, Program Oversight, Investigations and Enforcement; Deputy Executive Director for Management Services; Regional Administrators; Directors of the Offices of Nuclear Reactor Regulation, Analysis and Evaluation of Operational Data, Nuclear Material Safety and Safeguards, Nuclear Regulatory Research, Enforcement , Investigation, and State Programs; and senior managers from the Office of the General Counsel.

Region I Administrator Seeks SMM Action on IP2

OIG learned that paralleling NRC's inspection activity at IP2 from 1997 through 2000 was a series of attempts by the Region I Administrator to further heighten NRC oversight at the plant through the agency's SMM process. At the June 1997 SMM, the Region I Administrator presented his concerns regarding the declining performance of IP2 that was the result of significant equipment, human performance, and technical support performance issues that were apparent in late 1996. NRC Regional Administrators and senior managers told OIG that at the June 1997 SMM, the Region I Administrator made "a strong presentation" regarding IP2's performance and his belief that IP2 should be designated as a Watch List plant. However, the senior managers decided not to designate IP2 as a Watch List plant but to continue providing the heightened level of regional oversight underway at the time. According to the senior managers, and based on minutes of the SMM proceedings, the information presented at the SMM did not identify a situation where the plant was unsafe, a safety system was inoperable, or adverse trends were apparent. Thus, the senior managers determined that IP2 did not warrant agency-level action.

During the SMM held in January 1998, the Region I Administrator again presented IP2 for discussion asserting that there had been little change in performance in most respects over the prior 6 months; that recent inspections raised additional concerns with respect to performance; that NRC inspectors, rather than ConEd, continued to identify many of the performance problems, particularly in operations and engineering; and that equipment and human performance issues continued to be of concern. Additionally, the informality of processes contributed to problems observed in several areas, including technical specification implementation, procedural adherence, problem identification, and timely effective resolution of issues. OIG learned that this time, the consensus of the senior managers was to conduct a diagnostic-type review to obtain additional information on the plant's condition and not to issue a trending letter or put the plant on the Watch List. Again, the senior managers believed that Region I did not identify a situation where the plant was unsafe or a safety system was inoperable; however, they acknowledged that IP2 continued to exhibit performance weaknesses, and they noted that a definitive improvement trend was not apparent.

In July 1998, the Region I Administrator again presented IP2 at the SMM in the belief it should be designated as a Watch List Plant. He asserted that the performance at IP2 was largely unchanged during the preceding 6 months with respect to human performance and the control of plant activities. Additionally, the 1998 Independent Safety Assessment (ISA) conducted by ConEd identified some important deficiencies and weaknesses that existed at IP2 particularly in the areas of management and operations. Despite the Region I Administrator's presentation, the SMM again declined to designate IP2 a Watch List plant. This time, the SMM decided to maintain, rather than increase, the level of attention to allow the licensee a period of time to execute its performance improvement initiatives. The senior managers recognized that IP2 continued to have performance weaknesses, but again they believed that Region I did not identify a situation where the plant was unsafe or a safety system inoperable.

IP2 was not discussed during the April 1999 SMM. The Region I Administrator told OIG that he did not recommend that IP2 be presented for discussion because it had experienced no significant events since the last time he presented the plant for SMM discussion. He felt that in 1999, performance weaknesses still existed but that IP2 was no worse than in preceding years and was, in fact, slowly improving. He said he still would have preferred SMM action; however, he felt he lacked a basis for presenting the plant at the SMM.

SMM Designates IP2 as Agency Focus Plant in May 2000

In May 2000, the Region I Administrator presented IP2 at the SMM after the occurrence of two significant events at the plant, the August 1999 reactor trip and the February 2000 steam generator tube rupture. OIG learned that overall, the events and related findings during this assessment period represented issues that were of substantial significance; therefore, the senior managers categorized IP2 as an Agency Focus Plant under the revised SMM process.[15]

---

[15]In April 1999, the Commission approved SECY 99-086, "Recommendations Regarding the Senior Management Meeting Process and Ongoing Improvements to Existing Licensee Performance Assessment Processes." SECY 99-086 eliminated the "Watch List" and proposed that during SMM meetings, participants would

According to the SMM minutes, the senior managers concluded that the broad performance issues that had existed at IP2 for the past several years revealed a number of deficiencies in the plant's CAP and that IP2 improvement initiatives yielded some progress but, overall, were limited in remedying the underlying problems.

According to the Region I Administrator, the August 1999 and February 2000 events revealed the depth of IP2's performance problems and were evidence of the significant issues discussed at previous SMMs. Region I staff echoed this sentiment to the OIG, questioning why — given the inspection history, the identified problems, the NRC man-hours at the plant, and the history of civil penalties — IP2 was not put on the Watch List sooner.

Current Status of IP2

Region I staff has informed OIG that since March 2001, NRC has provided a significant amount of oversight and inspection effort at IP2. The Region I staff performed 12,950 hours of inspection activity at IP2 between March 1, 2001, and March 1, 2003, compared to an average of 8,297 hours at other single unit sites in Region I. (See Appendix B for a chronology of NRC inspection activity at IP2 during this time period.) Of the 12,950 hours of inspection performed at IP2 during this 2-year period, 2,216 hours were focused on engineering and PI&R compared to an average of 1,077 hours devoted to these areas at other single-unit Region I sites. The staff informed OIG that these figures indicate that during this period, IP2 has received about 1.5 times as much inspection as the average for other single-unit sites and about 2 times as much inspection pertaining to engineering and PI&R.

Annual assessments of plant performance[16] performed since the plant was categorized as an Agency Focus Plant in May 2000 indicate that IP2 performance has been improving, albeit slowly, since that time. NRC's annual assessment of plant performance for April 2, 2000, to March 31, 2001, found that while IP2 met all cornerstone objectives, it remained in the Multiple/Repetitive Degraded Cornerstone column of the NRC's ROP Action Matrix. According to the Region I staff, that assessment noted a number of issues in design control, equipment reliability, PI&R, and human performance. While some performance improvements were noted, progress was considered slow and limited in some areas. Region I staff noted that as of December 31, 2001, IP2 remained in the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix.

---

determine whether a plant warranted Agency Focus (characterized by NRC Executive Director for Operations and Commission involvement, e.g., issuance of an order), Regional Focus (managed by the regional administrator, e.g., issuance of a confirmatory action letter), or routine oversight.

[16]Under the ROP, NRC assesses licensee performance in various ways, including quarterly plant performance assessments based on inspection findings and performance indicator data. Regional offices conduct a more comprehensive review after the second quarter of the year (mid-cycle) to assist in planning inspections for the next 6 to 12 months. The regions also conduct an annual (end-of-cycle) review after the fourth quarter of the year to develop an annual performance summary for each plant and to plan inspections for the next 12 months. NRC uses an Action Matrix to assist staff in reaching objective conclusions regarding licensees' safety performance. The matrix allows for plants to be categorized into five possible results categories, or matrix columns, which indicate the plant's level of performance and the agency's required response. Categories (from lowest to highest performance) are (1) Unacceptable Performance, (2) Multiple/Repetitive Degraded Cornerstone, (3) Degraded Cornerstone, (4) Regulatory Response, and (5) Licensee Response.

Significant inspection activity continued during 2002, including an augmented PI&R inspection and supplemental team inspection in June and July 2002. OIG was told that in August 2002, IP2 had made sufficient progress to justify removal of the plant from the Multiple/Repetitive Degraded cornerstone into the Degraded Cornerstone column of the Action Matrix. OIG was told by the Region I Administrator that on February 7, 2003, NRC completed its end-of-cycle plant performance assessment of IP2 covering performance from January 1, 2002, through December 28, 2002. NRC concluded that during that time period, IP2 continued to operate in a manner that preserved public health and safety.

The Region I Administrator and staff told OIG that Region I fully utilized the regulatory tools it had available to deal with IP2. The Region I Administrator said that although the plant was never unsafe, improvement in IP2's performance might have been swifter had the plant been designated a "Watch List" plant by the SMM earlier. This designation would have sent a powerful message to the licensee concerning the need for improved performance.

The Region I Administrator commented that while the agency's senior managers designated the plant as an "Agency Focus Plant" in May 2000, this occurred after the plant had reversed its downward trend and, in fact, the designation had a relatively small impact on recent plant operations because the plant's declining performance had already been arrested as a result of earlier actions taken by the NRC. The Region I Administrator also noted that SMM deliberations were always thorough but that decisions were inherently difficult given the complexity of issues involved.

Additionally, the Region I Administrator commented to OIG that Entergy's purchase of IP2 in September 2001, had a considerable impact on plant performance. According to the Region I Administrator, Entergy conducted its own self-assessment of IP2 and subsequently committed significant resources to the plant. Furthermore, Entergy had experience operating other nuclear power plants, was aware of the need to inject resources to improve plant performance, and had those resources available. Entergy also understood the need to bring top management talent to operate the plant, which it did. According to the Region I Administrator, this shift in ownership facilitated the IP2 improved performance trend.

The Region I Administrator considered IP2's improvement as an NRC "regulatory success story." He stated that NRC's aggressive oversight and intervention arrested the decline in early 1996 and prevented IP2 from ever getting to the point where it was unsafe to operate. He acknowledged that IP2's improvement has been slow at times and often uneven, but that, overall, plant performance has steadily improved. In his view, the conditions that led to IP2's poor performance in the mid-1990s developed over a number of years and, therefore, required time to resolve. He credited NRC oversight efforts performed at IP2 since 1996 with having caused the plant to reverse its downward performance trend and begin its slow progress toward the performance improvement reflected in the NRC's recent assessment letters.

OIG FINDING

On four occasions between 1997 and 2000, the Region I Administrator sought additional NRC oversight for IP2 by seeking to have NRC's senior managers place IP2 on NRC's Watch List via the agency's Senior Management Meeting process. However, it was not until May 2000, after the August 1999 reactor trip and the February 2000 steam generator tube rupture, that NRC senior managers agreed that this form of heightened attention was appropriate. In May 2000, IP2 was classified as an Agency Focus Plant. Subsequent to being so designated, NRC annual assessments of plant performance indicated that IP2 had improved. OIG concurs with the Region I Administrator and his staff that placing IP2 on the Watch List sooner might have sufficiently motivated the licensee to cause earlier improved performance.

APPENDIX A
Summary of IP2 RPS Condition Reports

CR 199803574 identified a discrepancy between the RPS wiring configuration and a description in section 7.2.2.9 of the UFSAR of isolation between safety signals and annunciator and/or computer signals. Contrary to the UFSAR statement that "The center and front decks of RPS logic relays are used for annunciator and computer signals respectively," 22 RPS logic relays were found to violate this criterion.

CR 199900478 identified discrepancies between design drawings and the as-built configuration with respect to contact state associated with interposing relays for the low autostop oil pressure protection scheme. The corrective action for this condition involved revision of four drawings to reflect the field condition.

CR 199902274 identified "minor" inconsistencies affecting 14 RPS and ESF drawings. Corrective action involved revising the affected drawing based on comments received from an outside contractor who was tasked with the drawing review.

CR 199902835 identified three distinct discrepancies between plant drawings and the as-built condition. These discrepancies involved: RPS logic relays used to block the "Source Range High Influx at Shutdown" annunciator, drawings showing RPS relay contact configuration different from the as-built condition, and incorrect RPS relay nomenclature on plant drawings. The corrective action for this CR was limited to revising the affected drawings to agree with the as-found condition.

CR 199903445 was initiated because the drawing revisions prepared in response to CR 199902835 were in error. This CR also identified an additional drawing error in which the drawing showed the incorrect RPS relay contacts used for the Source Range High Flux at Shutdown annunciator block.

CR 199904968 identified another discrepancy between the design drawings and the as-found configuration of the RPS. This discrepancy involved contacts from RPS relay P10-2 that are used to defeat the Source Range Loss of Detector Voltage annunciator above 10% reactor power which are not shown on plant drawings. The corrective action for this CR involved a field verification of the configuration and revision of the affected drawing to reflect the as-found condition.

CR 200007597 identified a number of potential internal wiring related discrepant conditions in the reactor protection racks. Isolated cases of wire routing and/or terminations were observed to be inconsistent with routing/separation requirements stated in the UFSAR. In response to this CR an Operability Determination (OD) 00-018 was issued to address the wiring routing/separation issues. The OD determined that the RPS was operable.

CR 200008415 identified drawing discrepancies between Westinghouse RPS wire lists and field conditions, however, an operability determination concluded that this did not constitute an operability concern.

CR 200008818 identified a broken contact in a reactor trip relay, unidentified, unterminated switchboard wire with exposed lugs in RPS cabinets, and a mixing of wiring associated with computer/logic/annunciator functions. The broken contact has been repaired. A 200-degree hold was placed on this CR. The “Operability Review Note” by the Watch Engineer stated “200 degree hold for loose wires, etc.” The response to the unterminated (loose) wire issue was not addressed. The engineer who responded to the 200H action stated that he considered the unterminated wire a housekeeping issue and therefore, did not address it as part of the 200H response.

CR 200009499 identified additional conditions in which the wiring in the RPS racks violated statements in the UFSAR. The CR stated that “Wires (in RPS Racks 4 and 5) were carelessly strewn through multiple wire ways,” and “Had the original design been followed, there would have been no mixing (of circuit functions) and there would have also been half as many new wires to mix.” These issues were addressed in Operability Determination 00-018 which was conducted on CR 200007597 which found that the RPS was operable.

CR 200009641 identified six issues related to RPS wiring deficiencies or discrepancies, three of which were similar to or a repeat of issues identified in previous CRs. The new issues included a wire associated with an NIS power range logic relay with a splice that is not represented on plant drawings and single cable containing both 125 VDC logic protection power and 118 VAC instrument bus power. Both of these issues were addressed in Operability Determination 00-018.

CR 200010125 identified discrepancies between design drawings and the as-built configuration of the RPS. This CR also identified other CRs that described similar inconsistencies between design drawings and RPS wiring. A review of the corrective action associated with these CRs revealed that the CR actions were typically closed by revising the plant drawings to reflect the as-found configuration without performing a safety evaluation to determine the impact of the change on the design and licensing basis. In some cases the as-found condition affected the system design as depicted in the UFSAR text and/or figures. This CR also identified errors made in drawings as part of the corrective action for CR 199904968. Furthermore, this CR identified discrepancies between drawings and the as-found RPS wiring that had not been previously identified.

CR 200100327 summarized numerous issues identified in eight previously submitted CRs that documented a lack of configuration control and quality control of changes to the RPS wiring since 1998. The concerns raised in CR 200100327 were categorized as quality assurance requirements for design verifications, wiring changes resulting from modifications that could not be located and wiring separation not in accordance with the UFSAR. The eight CRs summarized in CR 200100327 are CR 200010125, CR 199803574, CR 199904968, CR 199902835, CR 199903445, CR 200007597, CR 200009499 and CR 200009641.

APPENDIX B
Chronology of Significant Inspections and Oversight at IP2, 1995 – 2003[1]

March 14, 1995	Inspection Report (IR) 1995-01, special safety inspection of AFW digital controller failure.
April 12, 1995	IR 1994-017 service water self-assessment inspection.
August 28, 1995	IR 1995-080, Operational Safety Team Inspection.
October 26, 1995	SALP report issued.
January 28, 1997	IR 1996-080, Integrated Performance Assessment Process (IPAP).
January 31, 1997	Confirmatory Action Letter (CAL) issued.
February 21, 1997	CAL closed.
March 31, 1997	Final SALP report issued.
May 1, 1997	Plant shutdown for refueling outage.
May 9, 1997	IR 1997-003 integrated inspection.
June 19, 1997	IR 1997-005, special inspection conducted for stuck open MSSV.
June 1997	IP2 discussed at Senior Management Meeting (SMM).
June 1997	Regional Administrator meets with ConEd Chief Executive Officer.
July 8, 1997	Plant startup from refuel outage.
July 26, 1997	Generator load rejection and reactor trip.
July 28, 1997	Reactor trip.
August 6, 1997	Shutdown.
August 8, 1997	IR 1997-008, special inspection of outage issues.
August 23, 1997	Reactor trip due to reactor coolant pump breaker testing logic error.
August 25, 1997	Plant startup.
September 29, 1997	IR 1997-010, special inspection of load reject and reactor trip.

[1] Information in this chronology was provided to OIG by Region I.

October 14, 1997	Plant shut down due to repetitive DB50 circuit breaker failures.
December 12, 1997	IR 1997-012, integrated inspection report, resident inspection and specialist review of safety-related breaker problems.
January 1998	IP2 discussed at SMM.
January 1998	Performance letter issued to ConEd - decision made to perform Operational Safety Team Inspection/Independent Safety Assessment.
February 13, 1998	IR 1997-013, special inspection of 480 Vac Breaker failures.
March 26, 1998	CAL 1-98-005 due to issues discovered during shut down not related to circuit breakers.
March 26, 1998	IR 1998-201, design inspection.
April 27, 1998	NRC restart action plan for IP2 issued.
May 1998	Independent Safety Assessment performed by ConEd.
June 3, 1998	IR 1998-005, NRC Evaluation Team (NET).
June 26, 1998	IR 1998-006, special inspection focusing on corrective actions regarding plant restart issues.
June 1998	Emergency preparedness exercise.
July 9, 1998	Revised NRC CAL 1-98-005 issued March 26, 1998.
July 1998	IP2 discussed at SMM.
September 16, 1998	IR 1998-012, followup NRC NET evaluation team inspection.
September 21, 1998	Reactor startup.
October 16, 1998	IR 1998-008, special Inspection of corrective action associated with restart issue.
October 23, 1998	IR 1998-014, NRC integrated inspection.
November 3, 1998	IR 1998-016, NRC special inspection of high efficiency particulate air (HEPA) filter deterioration.
January 29, 1999	IR 1998-018 NRC 40500 Corrective Action Program Inspection.
April 1999	Plant Performance Review.

June 1999	ConEd external assessments of operations, work control, and maintenance departments.
August 19, 1999	IR 1999-004 NRC team inspection report (Core Engineering Team).
August 31, 1999	Reactor trip and loss of offsite power.
September 14, 1999	Management meeting - Augmented Inspection Team (AIT) interim results.
September 23, 1999	Public exit meeting - AIT exit meeting.
September 1999	Emergency preparedness exercise.
October 13, 1999	Reactor startup.
October 19, 1999	IR 1999-008, AIT.
October 1999	IR 1999-013, AIT follow up team inspection commenced.
October 1999	Mid-cycle plant performance review letter issued.
November 23, 1999	Public Meeting - IP2 performance assessment results from September 1999 plant performance review.
December 21, 1999	Results of the follow-up inspection to the AIT (1999-013).
December 1999	IP2 Recovery Plan actions transferred to Business Plan.
January 5, 2000	IR 1999-014. Results of enforcement follow up of AIT for August 31, 1999 trip.
January 7, 2000	Drafted charter for the formation of the Indian Point Unit 2 oversight panel (IPOP).
February 1, 2002	Drafted IP2 oversight strategy.
February 15, 2000	Reactor trip - steam generator tube failure (SGTF).
March 1, 2000	SGTF meeting.
March 14, 2000	SGTF public meeting.
March 2000	Formation of IP2 communications team.
March 2000	Plant performance review letter.
April 28, 2000	NRC AIT SGTF IR 2000-002 issued.

May 23, 2000	IP2 discussed at SMM; letter issued characterizing IP2 as an "Agency Focus" plant.
June 25, 2000	Public meeting.
July 10, 2000	IR 2000-007, AIT SGTF follow-up.
July 27, 2000	IR 2000-010, NRC SGTF special inspection.
August 3-4, 2000	Regional Administrator site visit.
August 31, 2000	IR 2000-010, SGTF special inspection.
September 11, 2000	NRC Agency Focus Meeting. (Regional Administrator and NRR Deputy Director Site Visit)
September 26, 2000	Regulatory conference on SGTF "red" finding.
September 2000	Ongoing regional management briefings on cornerstone deficiencies, and plant performance issues throughout restart.
October 2, 16, 2000	Problem Identification and Resolution (PI&R) inspection.
October 5, 2000	EDO brief to discuss content of "Agency Focus" letter.
October 10, 2000	Assessment follow up (Agency Focus Update) letter.
October 11, 2000	ROP meeting held in Cortland Town Hall.
October 16, 2000	Operator requalification Inspection.
October 25, 2000	NRC - ConEd management meeting.
October 31, 2000	Significant Determination Process repanel (final determination of "red or yellow" finding for SGTF issues).
November 1, 2000	IP2 SGTF Lessons Learned Task Force (LLTF) report issued.
November 6, 2000	NRC on-site restart readiness reviews.
November 8, 2000	Mid Cycle review meeting conducted.
November 14, 2000	RI review of four system readiness reviews.
November 16, 2000	Public meeting.
November 16, 2000	NRC noted that the independent 125 VDC SSFA team performed a high quality review.

November 20, 2000	Issued red finding and Notice of Violation (NOV) for the poor SG inspection program that led to the SGTF.
November 27, 2000	NRC safety system readiness review inspection on the Safety Inspection system.
November 29, 2000	Mid cycle performance review and inspection plan letter issued.
December 1, 2000	Region I senior management site visit to IP2.
December 4, 2000	PI&R inspection report.
December 6, 2000	EDO briefing.
December 11, 2000	Plant heat up above 200 degrees - restart inspection begun.
December 18, 2000	IR 2000-014 design issues inspection.
December 20, 2000	NRC replied to ConEd's request for extension to respond to the red finding and NOV.
December 22, 2000	NRC Region I issues NRC review efforts/status letter.
December 30, 2000	Plant restarted.
January 2, 2001	Turbine trip due to low SG level.
January 5, 2001	Regional Administrator visits Congresswoman Kelly.
February 9, 2001	95003 multiple degraded cornerstone supplemental inspection.
February 26 - May 4, 2001	IR 2001-005, review reactor protection system (RPS) design issues.
February 27, 2001	Chilling effect letter issues.
March 1-2, 2001	Regional Administrator site visit and public exit meeting for 95003 inspection.
March 9, 2001	Chairman site visit with Regional Administrator and Executive Director for Operations.
April 3, 2001	Division of Reactor Safety (DRS) branch chief visit to IP2 - UFSAR verification project status.
April 10, 2001	IR 2001-002, (95003 Inspection) supplemental inspection report issued.

June 18, 2001	IR 2001-007, emergency preparedness (EP) exercise review and supplemental inspection of licensee actions to address three findings in the EP cornerstone area.
July 23, 2001	IR 2001-007, review of 2001 design engineering business plan and scope and 50.54 (f) commitment status.
July 23, 2001	IR 2001008, review of 2001 Design Engineering Business Plan Scope and 50.54(f) commitment status.
October 22, 2001	IR 2002013, NRC on-site to do initial inspection of the failure of three of six crews on licensed operator (LOR) examinations and to observe facility evaluate seventh crew; crew fails: four of seven = yellow finding.
November 5, 2001	IR 2001-010, review of licensee's safety injection (SI) safety system functional assessment (SSFA) and PI&R inspection.
November 27, 2001	IR 2001-011, NRC observes facility-led evaluation of an operating crew; while onsite, conducts regular-hours control room (CR) observations.
December 7, 2001	IR 2001-011, NRC- led evaluation of another operating crew; while onsite, conducts regular-hours CR observations.
December 16, 2001	IR 2001-011, NRC- led evaluation of 4 staff RO licenses.
January 28, 2002	IR 2001-014, review of licensee's self assessment and Fundamentals Improvement Plan (FIP), including the Design Basis Initiative (DBI).
February 7, 2002	IR 2002-007, NRC observes facility-administered evaluations (High Intensity Training (HIT).
March 21, 2002	IR 2002-007, NRC observes facility-administered evaluations (HIT).
March 21, 2002	IR 2002-009, supplemental inspection to review causes and corrective actions for yellow finding related to operator requalification.
June 24, 2002	IR 2002-010, augmented PI&R inspection, reviewed performance issues related to the multiple degraded cornerstone designation, progress implementing the FIP, and review of the degraded control room west wall fire barrier.
November 4, 2002	IR 2002-007, review of reactor protection system (RPS) wiring verification.
December 9, 2002	IR 2003-002, PI&R team inspection.
December 2002 - February 2003	IR 2003-003 and IR 2003-005 (both draft), team inspections to review TI 2515/148 and various other security issues.

January 27, 2003	IR 2003-004 (draft), engineering team inspection reviewed design and performance capability of component cooling water and offsite power supplies.

APPENDIX C
Summary of Escalated Enforcement Action from 1995-2000

1996-01, Enforcement Action 96-089, Significance Level (SL) III
10 CFR 50.59 (SL III) and 50.72 (SL IV)

Repair activities on central control room roof left ventilation system in unanalyzed condition for 2 months. Inadequate corrective actions.

1996-04, Enforcement Action 96-272, SL IV
Criterion XVI (SL IV) and Technical Specification (TS) 6.8.1. (SL IV)

1) Failure to maintain proper configuration control over containment isolation valve, contrary to procedure requirements.
2) Failure to preform required safety evaluation on procedure change.

1996-07, Enforcement Action 97-031, SL III ($50,000 civil penalty)
Criterion XVI (SL III)

Inadequate measures were taken to assure that the cause of each condition was determined and corrective action taken to preclude repetition.

1) Repeated surveillance test failures associated with the TDAFW pump's steam admission valve and discharge flow control valves. Valve damage subsequently identified.
2) Preconditioning of TDAFW pump by blowing down steam traps prior to testing. Adequate engineering review was not performed to support pump operability.
3) Multiple surveillance test failures associated with alternate safe shutdown system power transfer switches for the 23 and 24 service water pumps.
4) Untimely identification of degradation of PAB filter/fire deluge system control panel and associated circuits. System was incapable of performing design function. Poor implementation of an alarm response procedure's required actions.

1996-08, Enforcement Action 97-113, SL III ($50,000 civil penalty)
Criterion XVI (SL III), TS 6.8.1(SL IV), TS 6.5.1.6.a. (SL IV)

1) Failure to take adequate corrective actions following grit intrusion during the 1995 refueling outage. Resulted in inoperability of three of the four safety-related MFRV's and one low-flow bypass MFRV in January 1997.
2) Control of SG levels not in accordance with procedure and the failure to make temporary procedure changes to invoke administrative allowances for situation where deviation is necessary.
3) Failure to perform a required review of a vendor report that was used as the basis to support DG operability following the 1995 grit intrusion.

1996-80, Enforcement Action 96-509, SL III ($50,000 civil penalty)
Appendix R (SL III)

Fire protection features not provided to protect one train of systems - two instances.

1) Certain normal safe shut down instrumentation and the corresponding alternate safe shutdown instrumentation would be subject to fire damage.
2) Potential for hot shorts exists as a result of fire damage to cables associated with both the pressurizer PORV and block valves (a high/low pressure interface).

1997-03, Enforcement Action 97-191, SL III ($55,000 civil penalty)
Criterion XVI (SL III)

Failure to promptly identify and take corrective actions. Maintenance worker drilled into an electrical junction box, causing fire dampers in two safety-related electrical distribution rooms to actuate. Some dampers did not drop and other became physically restrained and only partially dropped. Condition went unaddressed by plant personnel for two days until questioned by NRC.

1997-08, Enforcement Action 97-367, SL III ($110,000 civil penalty)
TS 6.8.1 (SL III), Criterion XVI (SL III), TS 3.1.A.4.a (SL III), TS 4.18.c (SL III),
TS 4.2.1.(SL IV) - 5 violations

1) operation of the plant for 2.5 days outside technical specifications pressure and temperature curves with the OPS inoperable. Violation of TS 6.8.1.
2) Failed to consider ambient temperature condition on the pressurizer code safety valve set point. Violation of TS 4.2.1 Untimely and ineffective corrective actions. Inadequate 50.59 safety evaluation for a plant mod to remove the pressurizer block house roof. Inoperability of the code safety valves as prescribed by the technical specifications. Numerous opportunities existed for the staff to identify this issue.
3) Ingestion of hose in 21 recirculation pump. Poor engineering resolution to degraded pump performance that preceded the identification of the hose in the 1997 refueling outage. Indications are 21 recirculation pump inoperable since 1995. Inadequate corrective actions.

1997-13, Enforcement Action 97-576, SL III ($55,000 civil penalty)
Criterion XVI (SL III)

Failure to take prompt and appropriate corrective actions prior to voluntary shutdown in October 1997 to address the recurring DB-50 breaker failures to close on demand.

1997-15, Enforcement Action 98-028, SL IV
Criterion XVI (SL IV), TS 6.8.1 (SL IV) - 2 violations

1) ConEd’s failure to address degraded conditions in a timely manner on the post accident containment venting system (PACVS) and the hydrogen recombiner system.
2) An inadequate procedure for operation of the PACVS.

Office of Investigations- January 22, 1998, Enforcement Action 98–056, SL III
50.9 (SL III) - 2 Violations

1) On August 8, 1997, the emergency battery lights in the PAB were not tested per procedure. However, records were created that indicated the lights were tested. Technicians were not in room for long enough period to adequately test lights.

2) On August 8, 1997, surveillance test of EDG auxiliaries require double verification. Double verification of compressor was not performed. Records were created that indicate second verification was performed. Technician was not in the EDG building to be able to perform verification.

1998-02, Enforcement Action 98-192, SL III (\$55,000 civil penalty)
Criterion XI (SL III)

A significant number of technical surveillance testing discrepancies were identified through ConEd and NRC reviews. Failed to assure that all testing required to demonstrate that systems and components will perform satisfactorily in service, as specified in technical specifications, was incorporated into surveillance test procedures.

1999-014, Enforcement Action 99-319, SL II (\$88,000 civil penalty)
Criterion III (2 violations), Criterion V, Criterion XVI (SL II)

1) a. Design basis not correctly translated into specifications and procedures for mod to the 480 vital bus degraded voltage relays. Therefore, relays could not perform design basis function and correctly reset. Contributing to August 31, 1999 transfer of 480V bus from offsite power supply to the RDGs.
b. Requirement for auto operation of the Station Aux Transformer Load Tap Changer were not translated into procedures. As a result form September 9, 1998 to August 31, 1999, the 138kV offsite power system was unable to perform its function. Violated Technical specification 3.7. B.3.
2) Procedure did not adequately ensure proper calibration of DB-75 breaker trip units for the EDGs. Result EDG was inoperable from May 27, 1999 through August 31, 1999.
3) Condition adverse to quality with channel 4 of the reactor protection system (RPS) OTDT circuitry between January 1999 and August 31, 1999, resulting in a plant trip during maintenance on channel 3.

2001-010, Enforcement Action 00-179, Red Finding
Criterion XVI (Red)

A PWSCC defect was identified, signifying the potential for other similar cracks in low-row tubes. ConEd did not adequately evaluate the susceptibility for low-row tubes to PWSCC and the extent of degradation.
ConEd did not adequately evaluate the potential for hour-glassing based on the indications of the low-row tube denting. The increased stresses caused by the hour-glassing are a prime precursor for PWSCC.
1997 Steam generator inspection program was not adjusted to compensate for the

adverse effects of increased noise in detecting flaws, particularly when condition that increased the susceptibility to PWSCC existed.

These problems contributed to at least four tubes with PWSCC flaws in their small radius U-bends, being left in service following the 1997 inspection, until one tube failed on February 15, 2000.