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September 24, 1999

Dr. William Travers
Executive Director for Operations
United States Nuclear Regulatory Commission
Washington, D.C. 20555

SUBJECT: Consolidated Edison Company of New York, Inc. Preliminary Review of Issues Identified in the Union of Concerned Scientists Petition Pursuant to 10 CFR 2.206, Indian Point Unit 2, Docket 50-247, dated September 15, 1999

Dear Dr. Travers:

On September 15, 1999 Consolidated Edison Company of New York, Inc. (Con Edison), the owner and operator of the Indian Point Unit No. 2 nuclear plant, received a copy of a petition submitted to the U.S. Nuclear Regulatory Commission (NRC) by the Union of Concerned Scientists (UCS) pursuant to 10 CFR 2.206 of the Commission's regulations. The petition relates to a plant trip that occurred at Indian Point on August 31, 1999. As discussed with members of the NRC Staff, we are providing our assessment of whether certain issues enumerated in the petition need be fully resolved prior to the resumption of operations at the facility. Five issues are identified in the September 15 petition, and two additional issues were subsequently identified by the UCS in a September 22 supplement. Each of these issues has been evaluated separately. For the reasons set forth below, Con Edison has determined that each of the issues raised by the petition as supplemented has been already addressed in such a manner that assures that no issue raised by the petition provides a basis for deferring resumption of power operations.

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Our receipt of the petition followed a public meeting held at the NRC's Region 1 offices on September 14, 1999. The purpose of this meeting, which was attended by a UCS representative and other interested members of the public, was to discuss the licensee's Recovery Plan setting forth both near-term and longer-term actions to assure that its present and future operations will be conducted in full compliance with all applicable licensing requirements and in a manner which assures public health and safety. Our Recovery Plan sets forth the process and describes the actions undertaken by Con Edison following the August 31 trip. Copies of the recovery plan were made available to persons attending the September 14 meeting.

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The Recovery Plan establishes the structure and articulates the logic which Con Edison has pursued following the August 31 trip, dividing the effort into distinct assessment and recovery phases. Several separate initiatives were begun, and are in some instances continuing under the recovery plan. A meticulous event chronology has been prepared, and detailed inquiries have been conducted into the response of the plant's electrical systems to the August 31 trip. Analysis of the risk significance of the events of August 31 has been performed utilizing sophisticated probabilistic risk assessment tools. A utility assistance team comprised principally of non-licensee industry experts conducted an independent assessment of the events of August 31, utilizing personnel interviews, documentation reviews, and field inspections. The utility assistance team reported its findings to Con Edison senior management, and the team's written observations form a part of the recovery plan. Detailed and comprehensive post-trip recovery action plans were developed and are being implemented in the areas of command and control, plant processes, event response support, emergency planning, training, communications, and engineering.

The UCS petition asserts that four apparent violations of the plant's design and licensing basis were associated with the August 31 event. The apparent violations identified by UCS relate to station battery design licensing basis, omission of circuit breaker corrective actions, diesel generator reliability, and the licensing status of voltage relay surveillance intervals. A fifth issue raised by the petition questioned the reliability of the plant-specific risk assessment methodology utilized for assessing the risk significance of plant configuration and operability status. The two supplemental issues raised by UCS on September 22 refer to the adequacy of station blackout procedures, and the consistency of station procedures for the automatic actuation status of the tap changer with the plant's licensing basis.

Con Edison's recovery plan is sufficiently comprehensive so that it addresses and satisfactorily resolves each of the seven discrete issues identified by the petition as supplemented. The scope of the recovery plan was intentionally drawn in a broad fashion such that issues, such as the ones in the petition, identified by in-depth analysis would be resolved in a manner that assures conformity with licensing requirements when plant operations resume.

The basis for this conclusion with respect to each of the seven concerns identified is provided below.

Issue 1: Apparent violation of station battery design and licensing basis

The station batteries functioned as designed during the event. The UFSAR credits the batteries as being designed for two hours of operation under expected shutdown loads without any AC power for charging. Station battery 24 successfully supplied the shutdown load for approximately 7 hours and 22 minutes. A thorough engineering review of the effects of the discharge on 24 battery has been performed with the technical advice and

support of the battery manufacturer and industry experts, and special procedures for recharging and testing the battery prior to declaring it operable again were developed. One of the 58 cells required replacement. The battery is operable.

The concerns with respect to the coping duration for a station blackout event do not apply to the event on August 31. Normal, alternate, and emergency power supplies to the station were available, or could have been made available, throughout the event. The reactor coolant pumps, the condensate pumps, and two of the three auxiliary feedwater pumps remained in service or available throughout the event. The plant was shutdown throughout the event. In addition, had the plant been operating, the plant had the ability to conduct a safe shutdown without reliance on station blackout coping strategies at all times. Additionally, there are two DC control power sources available to each Emergency Diesel Generator (EDG) and 480 volt circuit breaker for engineered safeguard equipment. The loss of 24 Battery alone would not have prevented the starting of 23 EDG if required, or the proper operation of 480 volt switchgear for engineered safeguards equipment. Thus this issue is adequately resolved.

Issue 2: Apparent failure to adequately correct Circuit Breaker problems

A root cause evaluation for the opening of the output circuit breaker from 23 EDG to bus 6A as well as corrective actions and an extent of condition review for the cause or causes identified is required by the Recovery Plan, assuring that this issue will be fully addressed prior to returning the plant to service. The results of the root cause investigation revealed that the Amptector solid state trip device on 23 EDG was improperly set at too low a value (3,200 amps instead of 6,000). This in turn was attributed to the fact that the 6000 amps setting was made at a value at the extreme end of the "fine" adjustment dial for the instrument where a relatively slight movement of the dial can cause a large variation in the trip value. This problem is significantly different from the historical mechanical problems previously encountered and corrected with the DB-50 circuit breakers that are described in the discussion of this issue in the petition. The discovery of this problem does not invalidate any of the results of the earlier root cause evaluations or their associated corrective actions. Thus this issue is adequately resolved.

Issue 3: Apparent unreliability of Emergency Diesel Generators

All of the Emergency Diesel Generators (EDG) performed as designed during the event on August 31, 1999. The difficulty in supplying bus 6A from 23 EDG was with the output circuit breaker as described in the response to issue 2 above and not related to the any problem with the Diesel Generator itself. All of the EDGs are currently meeting their maintenance rule performance objectives and are in 10 CFR 50.65 (a) (2) status. EDG reliability is not a challenge to safe restart and operation of the plant. Therefore, this issue is adequately resolved.

Issue 4: Potentially unjustified license amendment for undervoltage and degraded voltage relay surveillance intervals

The undervoltage and degraded voltage relays functioned as designed during the event on August 31. Their safety function is to ensure that an undervoltage condition on the 480 volt buses, for any reason, will cause the safety related buses to be isolated from the non-safety related 6.9KV power source and to receive power from the safety related Emergency Diesel Generators. Surveillance testing of these devices ensures that they operate at the proper setpoints. The operation of the tap changer on the station auxiliary transformer is not checked nor is it required to be checked as part of this surveillance test. The extension of the surveillance interval for the undervoltage and degraded voltage relays from 18 to 24 months did not reduce safety margins at the plant. Thus, this issue is adequately resolved.

Issue 5: Apparent errors and non-conservatisms in individual plant examination

The "potential problem" statements used in developing this issue in the petition do not appear to be based on usual probabilistic risk assessment techniques. In particular:

- The availability of the gas turbines was irrelevant to the risk in this event since both 138KV and 13.8KV power remained available.
- 23 Auxiliary Feedwater pump did not fail to start or fail to run (power was not available to the pump, which is the condition to which risk is properly assigned)
- 22 Auxiliary Feedwater Pump did not fail to run and was not in a run out condition. Operators started and secured the turbine driven Auxiliary Feedwater pump as needed to control steam generator water level.
- There was no fault on the 6A bus
- 23 Emergency diesel Generator did not fail to start.
- Neither a High Head Safety Injection Pump nor a Component Cooling Water Pump failed to start (power was not available from bus 6A, and risk is properly assigned to that condition)

As a part of the station response to this event, an expert in the field of risk assessment from another nuclear utility performed a review of the Indian Point Probabilistic Safety Assessment. He concluded that the Indian Point model is adequate in predicting the event scenario (of loss of bus 6A following the trip) and in assessing the safety significance of losing bus 6A. He noted that the station staff's initial estimate of the conditional core damage probability of 1.87E-3 included conservatisms and he suggested modeling of main Feedwater/condensate recovery to address this potential conservatism. When this recovery method is included in the risk calculations using the plant conditions that existed during the event on August 31, a conditional core damage probability of 1.88 E-4 was determined. For this event we conclude that the Indian Point Probabilistic Safety Assessment Model is conservative by a factor of approximately 10. Thus, this concern is adequately resolved.

Issue 6: Apparent lack of procedures/lack of capability to respond to a station black-out event (based on transcript of September 22 telephone meeting)

There are adequate station procedures in place for dealing with a station blackout and for the loss of all four 480 volt buses. Operators are trained and periodically tested in the simulator on the use of these procedures. Furthermore, the plant was not in a blackout condition on August 31, and these procedures did not apply to the existent plant conditions. The starting of a gas turbine would not have provided any benefit during the event on August 31 because 13.8 kV power was already available. The delay in restoring power to bus 6A was associated with the activities required to verify that there was not a fault condition on the bus rather than a problem with the availability of power. These are not conditions that would be expected in a station blackout event. The relationship that the petition draws between the event of August 31, and a station black-out event does not have technical merit, but in any event we are confident that adequate procedures, training and equipment are in place to safely handle a station black-out event. On August 31, 1999, there was not a procedure in place to deal with the loss of a single 480 volt safety bus. This deficiency is being appropriately addressed by the recovery plan, including revision of applicable procedures. Therefore, this issue raised by UCS is adequately resolved.

Issue 7: Potential for other commitments to NRC not being performed
(based on transcript of September 22 telephone meeting)

The station event review identified that operating procedures did not properly reflect the importance of maintaining the station auxiliary transformer tap changer in automatic control. In the Safety Evaluation Report (SER) for Technical Specification amendment 165, the automatic function of the station auxiliary transformer tap changer to maintain 480 volt bus voltage following a fast transfer from internal to external power is described. Therefore operation of the tap changer in automatic must be considered part of the licensing basis. This information was not conveyed or captured in the appropriate operating procedures at the time the Technical Specification was implemented. It should be noted that the tap changer position had no effect on the degraded voltage protection circuitry, which functioned as designed. As part of the recovery plan, an extent of condition review is being performed for both Technical Specification Safety Evaluation Reports and plant modification safety evaluations to determine if this is an isolated case or if a more exhaustive review is required. These reviews to date have not discovered any situations directly affecting reactor safety where commitments have not been met. The results of the extent of condition review will be addressed prior to startup. Thus, this matter is adequately resolved.

Based upon the foregoing and the extensive effort undertaken in connection with the recovery plan, Con Edison concludes that the petition issues do not present any basis for deferral of plant startup. We do not mean to suggest, however, that the work activities undertaken pursuant to the recovery plan are complete. To the contrary, many recovery plan activities are continuing, although now nearing completion. Additional areas to

pursue may arise as the result of the NRC's Augmented Inspection Team public meeting on September 27. However, recovery plan work in those areas related to the UCS petition issues has been completed to an extent that fully assures compliance with relevant licensing requirements when power operations are resumed. As we proceed on our Recovery Plan, if any new issues are uncovered, we will advise you promptly.

If we can provide further information on these issues, please let me know.

Very truly yours,

A. Alan Blind

A. Alan Blind
Vice President

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September 15, 1999

Dr. William Travers
Executive Director for Operations
United States Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: PETITION PURSUANT TO 10 CFR 2.206, INDIAN POINT UNIT 2, DOCKET NO. 50-247

Dear Dr. Travers:

The Union of Concerned Scientists submits this petition pursuant to 10 CFR 2.206 requesting that the operating license for Indian Point Unit 2 be modified or suspended to prevent restart until there is reasonable assurance that its licensee is in substantial compliance with the terms of the plant's operating license and has proper consideration for public health and safety. As detailed in the attachment, the August 31, 1999, near-miss at the facility revealed a number of apparent non-conformances with very serious safety implications. Adequate protection of public health and safety dictates these problems be fully resolved before the plant resumes operation. UCS additionally requests a public hearing into this matter be held in the vicinity of the Indian Point Unit 2 facility prior to its being authorized to restart.

Background

On September 28, 1973, the Atomic Energy Commission (AEC) issued an operating license to Consolidated Edison Company of New York, Inc. for Indian Point Unit 2. The AEC issued that license after having determined, among other things, that:

> "The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.
>
> "There is reasonable assurance: ... (ii) that the activities authorized by this operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission."[1]

Thus, the operating license for Indian Point Unit 2 was granted partly on the explicit assumption that the licensee would operate the facility in conformance with the rules and regulations of the AEC (now NRC).

The reactor at Indian Point Unit 2 automatically shut down at 2:30pm on August 31, 1999. Shortly after the reactor tripped, an undervoltage condition was sensed on the 480 volt safety buses. This caused all three emergency diesel generators (EDGs) to automatically start and to connect to their associated 480 volt safety buses. However, the output breaker for one of the diesel generators (23 EDG) re-opened immediately after closing to connect that EDG to its safety bus (6A). The output breaker failure left 480 volt safety bus 6A powered solely from its associated battery (24 DC Battery). Approximately seven (7) hours later, 24 DC Battery was discharged leaving 480 volt safety bus 6A de-energized and causing the

[1] United States Atomic Energy Commission, Facility Operating License, License No. DPR-26 Amendment No. 4, September 28, 1973.

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loss of instrument bus 24. The loss of this instrument bus disabled approximately 75 percent of the annunciators in the control room, which triggered the declaration of an emergency condition. Power to 480 volt safety bus 6A was restored around 1am on September 1, 1999 when 23 EDG was re-connected.[2]

Basis for Requested Actions

UCS reviewed the publicly available information on this event. UCS also reviewed the publicly available information on the design and licensing bases for safety equipment whose operation or mal-operation contributed to the severity of this event. Finally, UCS attended the public meeting held in the NRC's Region I offices on September 14, 1999, during which the owner of the plant explained what had happened. As detailed in the attachment, there are at least four apparent violations of the plant's design and licensing bases revealed by the August 31, 1999 event:

Issue 1 – Apparent Violation of Station Battery Design and Licensing Bases

Issue 2 – Apparent Failure to Adequately Correct Circuit Breaker Problems

Issue 3 – Apparent Unreliability of Emergency Diesel Generators

Issue 4 – Potentially Unjustified License Amendment for Undervoltage and Degraded Voltage Relay Surveillance Intervals

In addition, the event revealed potential problems with the plant-specific risk assessment developed by the licensee and now used to establish priorities:

Issue 5 – Apparent Errors and Non-Conservatisms in Individual Plant Examination

The first four issues, if valid, have clear and direct safety implications because they involve equipment explicitly required to function to mitigate accidents. The fifth issue, if valid, has indirect safety implications because it involves information used by the plant's owner to schedule maintenance and inspections on equipment implicitly required to function to mitigate accident. Issues with potential safety implications must be taken seriously at all nuclear power plants, but particularly when the nuclear plant is close to a densely populated area. According to the NRC's plant information book for Indian Point Unit 2 (www.nrc.gov/AEOD/pib/reactors/247), the population distribution for the facility is:

16,774 individuals residing within 2 miles
73,935 individuals residing within 5 miles
237,338 individuals residing within 10 miles

Thus, there are at least 237,338 very good reasons to resolve these potential safety issues before Indian Point Unit 2 resumes operation.

How serious was the August 31, 1999, event? According to the plant's owner:

> "With the Reactor tripped and Bus 6A de-energized, the PRA [probabilistic risk assessment] analysis yielded a value of 1.8E-3 conditional core damage frequency. In practical terms, there was an approximately 2 in a 1000 chance that additional failures, such as the loss of the remaining aux feed water pumps, could have occurred that would have resulted in core damage. For comparison, this value was 100-200 times greater than that associated with normal plant operation with all 480V buses energized."[3]

[2] Nuclear Regulatory Commission, Preliminary Notification of Occurrence PNO-I-99-040, September 1, 1999.
[3] Consolidated Edison, "Indian Point 2 Recovery Plan," Revision 0, September 13, 1999.

Thus, the event at IP2 on August 31, 1999, endangered the health and safety of the public at least 100 times more than the danger level normally associated with the plant.

How did the plant's management respond to this heightened threat? Ninety minutes after the August 31, 1999, event began and with 480 volt safety bus 6A still de-energized leaving the plant in a condition 100 to 200 times riskier than when it was operating, the senior managers at Indian Point 2 met to discuss actions needed to restart the plant.[4]

Thus, IP2 management's focus was clearly on the financial aspects of the plant rather than the health and safety of the people living near the plant.

On March 28, 1979, the Three Mile Island Unit 2 reactor core experienced a partial meltdown. A Congressional investigation into that accident determined its six primary causes to be:

1. Malfunctions of plant equipment
2. Plant operators and managers inappropriately overrode the automatic safety equipment
3. Major weaknesses in the design of the plant, including a system of control room alarms that would "provide little, if any, immediate assistance in diagnosing a major transient or in assigning priorities to accident conditions"
4. Emergency procedures that "were vague, confusing, incomplete and not fully understood by plant personnel"
5. Weaknesses in the operator training program, including "limited training in multiple-failure accidents" and "limited training in the basics of nuclear power plant physics and behavior"
6. Confusing information and problems with instrumentation.[5]

The August 31, 1999, event at Indian Point Unit 2 – occurring more than twenty years after the TMI-2 meltdown – replicated five of its six causes:

1. Malfunctions of plant equipment:

   (a) The tap changer for the station auxiliary transformer was in manual, instead of being in automatic as required by the plant's licensing basis. This failure caused the undervoltage condition on the 480 volt safety buses.

   (b) The overcurrent protection setting for the output breaker on 23 EDG was set at 3,500 amps instead of at 6,000 amps as required by the plant's design bases. This failure caused the de-energization of 480 volt safety bus 6A and the ultimate loss of two of the three auxiliary feedwater pumps, one of the four power operated relief valves (PORVs), one of the four DC buses, one of the three safety injection pumps, one of the three 480 volt safety buses, and one of the three component cooling water pumps.

   (c) The reactor trip was caused when a spurious over-temperature/differential-temperature condition occurred during a maintenance activity. A similar "spike" had occurred the previous day and several times in the past, but "Plant and Maintenance management [were] not aware" of the malfunctions.[6]

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[4] Robert Masse, Plant Manager, Indian Point 2, Presentation to Nuclear Regulatory Commission, September 14, 1999.

[5] Subcommittee on Nuclear Regulation for the United States Senate Committee on Environment and Public Works, "Nuclear Accident and Recovery at Three Mile Island: A Special Investigation," June 1980.

[6] Pat Russell, Team Leader – Utility Assistance Team, to Bob Masse, Plant Manager – Indian Point 2, "Results of Assessment – IP2 Reactor Trip and Notification of Unusual Event on August 31, 1999," September 7, 1999.

2. Plant operators and managers inappropriately overrode the automatic safety equipment:

   A Utility Assessment Team investigating the event concluded that "Reviews of applicable Technical Specifications were insufficient to capture all required actions."[7] Thus, the operators failed to comply with the plant's license requirements governing safety equipment.

3. Major weaknesses in the design of the plant, including a system of control room alarms that would "provide little, if any, immediate assistance in diagnosing a major transient or in assigning priorities to accident conditions":

   Approximately 75 percent of the control room alarms at Indian Point Unit 2 are powered from 24 DC Instrument Bus off 24 DC Bus. When the station batteries powering that bus discharged, nearly 75 percent of the control room alarms were disabled.

4. Emergency procedures that "were vague, confusing, incomplete and not fully understood by plant personnel":

   (a) Prior to this event, IP2 did not even have an approved procedure for restoring power to 480 volt safety bus 6A.[8]

   (b) The guidance on emergency action levels (EALs) was vague and confusing, contributing to the failure to declare an emergency condition shortly after 480 volt safety bus 6A was de-energized.[9]

   (c) A Utility Assistance Team investigating the event concluded that "Event mitigation and system restoration plans [were] not formalized nor documented."[10]

5. Weaknesses in the operator training program, including "limited training in multiple-failure accidents" and "limited training in the basics of nuclear power plant physics and behavior":

   (a) A Utility Assessment Team investigating the event concluded that "General knowledge of plant batteries and dc electrical systems, and the significance of these systems to the safe operation of the plant, appears weak" and "Senior managers need orientation on Technical Specifications, Emergency Plan, and safety systems."[11]

   (b) The plant's owner committed to train its operators on the proper way to restore power to one 480 volt safety bus.[12]

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[7] Pat Russell, Team Leader – Utility Assistance Team, to Bob Masse, Plant Manager – Indian Point 2, "Results of Assessment – IP2 Reactor Trip and Notification of Unusual Event on August 31, 1999," September 7, 1999.
[8] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999.
[9] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999, and Augmented Inspection Team Member, Nuclear Regulatory Commission, Remarks During the Con Ed Presentation to Nuclear Regulatory Commission, September 14, 1999.
[10] Pat Russell, Team Leader – Utility Assistance Team, to Bob Masse, Plant Manager – Indian Point 2, "Results of Assessment – IP2 Reactor Trip and Notification of Unusual Event on August 31, 1999," September 7, 1999.
[11] Pat Russell, Team Leader – Utility Assistance Team, to Bob Masse, Plant Manager – Indian Point 2, "Results of Assessment – IP2 Reactor Trip and Notification of Unusual Event on August 31, 1999," September 7, 1999.
[12] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999.

6. Confusing information and problems with instrumentation

   No problems reported as of yet.

At least Three Mile Island had an excuse – it had only been operating for a year when the accident occurred. Indian Point Unit 2 was been operating for twenty six (26) years. Yet, despite that experience and the benefit of the TMI-2 lessons learned, things at IP2 was in such disarray that it had five of the six problems that caused a reactor meltdown.

During a September 14, 1999, meeting at the NRC's regional offices in King of Prussia, Pennsylvania, IP2's management outlined a lengthy 'recovery plan' in response to the event. If fully and successfully implemented, that plan will – at best – correct the specific problems revealed by the August 31, 1999, event. However, the majority of these problems are caused by systematic process breakdowns including inadequate procedures, inadequate training, and plant configuration errors. The company's plan simply does not contain sufficient activities that provide reasonable assurance that problems in other safety systems resulting from these same process breakdowns are identified and corrected, prior to restart. Safety at this facility must not be allowed to rely on a "trial and error" approach.

Requested Actions

UCS requests that the operating license for Indian Point Unit 2 be modified or suspended to prevent the reactor from resuming operation until the five issues identified in the attachment have been fully resolved. In lieu of a suspension or modification of the license, the issuance of a Confirmatory Action Letter or an Order requiring these issues to be fully resolved prior to restart would be acceptable.

UCS additionally requests a public hearing into this petition be conducted in the vicinity of the plant prior to the its restart being authorized by the NRC. Mr. David Lochbaum, UCS's Nuclear Safety Engineer, spoke with Mr. Jeffrey F. Harold, NRC Project Manager for Indian Point Unit 2, by telephone on September 10, 1999, and was informed that the report by the NRC's Augment Inspection Team (AIT) regarding the August 31, 1999, event might not be issued until after the facility resumes operation. The AIT's exit meeting is scheduled for September 20, 1999, and the report will probably not be issued for at least four weeks. Mr. Lochbaum spoke with Mr. A. Alan Blind, Vice President – Nuclear Power for Consolidated Edison Company of New York, Inc., following the September 14, 1999, public meeting in King of Prussia about the IP2 restart date. Mr. Blind indicated that he did not know if the restart would be within the next four weeks. UCS believes that a formal hearing into the safety issues raised by this petition is warranted before the NRC authorizes the restart of the plant.

Sincerely,

David A. Lochbaum

David A. Lochbaum
Nuclear Safety Engineer
Union of Concerned Scientists

Attachment: as stated

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Issue 1 – Apparent Violation of Station Battery Design and Licensing Bases

The reactor at Indian Point Unit 2 automatically shut down at 2:30pm on August 31, 1999. Shortly after the reactor tripped, an undervoltage condition was sensed on the 480 volt safety buses. This caused all three emergency diesel generators (EDGs) to automatically start and to connect to their associated 480 volt safety buses. However, the output breaker for one of the diesel generators (23 EDG) re-opened immediately after closing to connect that EDG to its safety bus (6A). The output breaker failure left 480 volt safety bus 6A powered solely from its associated battery (24 DC Battery). Approximately seven (7) hours later, 24 DC Battery was discharged leaving 480 volt safety bus 6A de-energized and causing the loss of instrument bus 24. The loss of the instrument bus disabled more than 75 percent of the annunciators in the control room. Power to 480 volt safety bus 6A was restored around 1am on September 1, 1999 when 23 EDG was re-connected.[13]

The August 31, 1999, event appears to violate the design and licensing bases for the station batteries in the following ways:

> "The licensee has stated that the AAC [alternate alternating current] power source meets the criteria specified in Appendix B of NUMARC 87-00, is available within one hour of the onset of the SBO [station blackout]event, and has sufficient capacity and capability to operate the systems necessary for coping with an SBO for a duration of 8 hours."[14]
>
> *Potential Problem: IP2 is licensed with an 8 hour coping duration for the station blackout rule (10 CFR 50.63). However, it took the licensee nearly 10½ hours – far longer than the 8 hour coping duration – to restore power to 480 volt safety bus 6A.*
>
> "The licensee has performed calculations and determined that there is sufficient battery capacity for one hour at which time the AAC source will be available to power the battery charger for one division."[15]
>
> *Potential Problem: IP2 is licensed based on the AAC source (one of three gas turbines) being made available within one hour. However, the licensee failed to connect the AAC source to 24 DC Battery in the seven (7) hours it took for the battery to fully discharge.*
>
> "Section 8.2.3.5 of the plant's UFSAR states that the batteries are designed for two hours of operation with the expected shutdown load without any AC power for charging. In an SBO scenario, the batteries are only required to last for one hour, after which AAC power will be available to provide the necessary charging. ... If both divisions' batteries are not charged by the AAC source, the licensee needs to include in its procedures a means to prevent the uncharged batteries from excessive discharge."[16]

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[13] Nuclear Regulatory Commission, Preliminary Notification of Occurrence PNO-I-99-040, September 1, 1999.

[14] Francis J. Williams, Jr., Project Manager, Nuclear Regulatory Commission, to Stephen B. Bram, Vice President – Nuclear Power, Consolidated Edison Company of New York, Inc., "Staff Evaluation of Indian Point Nuclear Generating Station Unit No. 2, Response to the Station Blackout Rule," Section 2.2.2 – Proposed AAC Power Source, November 21, 1991.

[15] Francis J. Williams, Jr., Project Manager, Nuclear Regulatory Commission, to Stephen B. Bram, Vice President – Nuclear Power, Consolidated Edison Company of New York, Inc., "Staff Evaluation of Indian Point Nuclear Generating Station Unit No. 2, Response to the Station Blackout Rule," Section 2.3.2 – Class 1E battery capacity, November 21, 1991.

[16] Francis J. Williams, Jr., Project Manager, Nuclear Regulatory Commission, to Stephen B. Bram, Vice President – Nuclear Power, Consolidated Edison Company of New York, Inc., "Staff Evaluation of Indian Point Nuclear

Potential Problems: The licensee operated 24 DC Battery for nearly five (5) hours longer than the design duration of two (2) hours specified in UFSAR Section 8.2.3.5. In addition, the licensee did not prevent 24 DC Battery from excessive discharge.

"The original Indian Point Unit No. 2 design is based on the philosophy of maintaining all engineered safeguards equipment operational following the loss of a D.C. feed. ... The original design was modified to provide station batteries 23 and 24 which were installed at Indian Point Unit No. 2 to provide contingency power supplies to 120 VAC Vital Instrument Buses 23 and 24, respectively. ... Under the proposed system, at least two (2) of the four (4) batteries would have to fail before we would lose a single diesel generator or 480 VAC switchgear. Even in this condition, redundant loads will still be supplied by the remaining power sources."[17]

Potential Problem: The loss of a D.C. feed, namely 23 EDG, disabled some engineered safeguards equipment.

The safety implications of this issue, if valid, are significant. The station batteries are vital safety equipment that provide DC power to emergency equipment immediately following a loss of offsite power. According to the plant's owner, the DC buses that are powered by the station batteries are the sixth most important system for preventing reactor core damage at Indian Point 2.[18] The station batteries, for example, provide control power to permit the emergency diesel generators to automatically start and connect to their associated loads. In addition, the station batteries are the sole source of electricity during a station blackout event (defined as a loss of offsite power concurrent with the failure of the onsite emergency diesel generators). During a station blackout event, the station batteries are needed to supply power to emergency lighting and to controls and instruments used by the operators to monitor plant conditions.

Issue 2 – Apparent Failure to Adequately Correct Circuit Breaker Problems

The reactor at Indian Point Unit 2 automatically shut down at 2:30pm on August 31, 1999. Shortly after the reactor tripped, an undervoltage condition was sensed on the 480 volt safety buses. This caused all three emergency diesel generators (EDGs) to automatically start and to connect to their associated 480 volt safety buses. However, the output breaker for one of the diesel generators (23 EDG) re-opened immediately after closing to connect that EDG to its safety bus (6A).[19]

According to the plant's owner, the 23 EDG output breaker re-opened due to an overcurrent condition. The overcurrent protection for this breaker was supposed to have been set at 6,000 amps, but had been improperly set at approximately 3,500 amps by plant personnel in May of this year. Shortly after 23 EDG was connected to 480V safety bus 6A, two emergency pumps automatically started as required. Their combined current draw exceeded the 3,500 amp overcurrent setpoint which tripped the output breaker and de-energized the safety bus.[20]

Generating Station Unit No. 2, Response to the Station Blackout Rule," Section 2.3.2 – Class 1E battery capacity, November 21, 1991.

[17] William J. Cahill, Jr., Vice President, Consolidated Edison Company of New York, Inc., to A. Schwencer, Chief – Operating reactors Branch No. 1, Nuclear Regulatory Commission, April 23, 1980.

[18] Consolidated Edison, "Indian Point 2 Recovery Plan," Revision 0, September 13, 1999.

[19] Nuclear Regulatory Commission, Preliminary Notification of Occurrence PNO-I-99-040, September 1, 1999.

[20] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999.

This plant site has experienced a inordinately high number of breaker problems in recent years:

> "On October 14, 1997, Consolidated Edison Company of New York voluntarily shutdown its Indian Point 2 Nuclear Power Plant (IP2) because of concerns about the operability and reliability of its safety-related 480-V Westinghouse Type DB-50 circuit breakers. The action was taken after experiencing recurring problems with these breakers to either close on demand or to remain closed. ... An NRC inspection identified several weaknesses associated with the licensee's corrective maintenance, preventive maintenance, and other corrective actions concerning circuit breakers. In June 1997, the licensee hired a contractor to perform a root-cause analysis. The contractor's report did not discuss all the possible failure modes and erroneously concluded that the DB-50 breaker failures were caused by malfunctioning solid-state trip devices (Amptectors) and operating mechanism binding caused by accumulated dust and dirt contaminating the mechanism's lubricant. The inadequate root-cause analysis led to the occurrence of more failures, which eventually prompted the October shutdown. Before the plant shutdown, the licensee did not vigorously pursue a root cause after experiencing a breaker failure. Typically, a failed breaker would be removed from service and the preventive maintenance procedure would be performed to restore it to an operable status without identifying the cause of the problem. ... Following the plant shutdown, the IP2 licensee conducted an extensive testing program to determine the root cause of the breaker failures. High-speed video, static and dynamic closing coil current measurements, component displacements, and force measurements were made, which identified several contributors to breaker failures. Refer to NRC Inspection Report 50-247/97-13 (Accession #9802250110) for further details. The licensee has developed useful diagnostic tools that could help in revealing or predicting breaker performance problems."[21]

The NRC included these breaker problems as one of four violations cited in a $110,000 fine imposed on the plant's owner:

> "The third violation, which is set forth in Section II of the enclosed Notice, involved your failure to determine the cause and take adequate corrective actions to preclude repetition of a significant condition adverse to quality involving 480 volt (V) safety-related circuit breakers. Specifically, between August 1993 and May 1997, there were multiple instances in which Westinghouse DB-50 480V circuit breakers failed to close on demand. Although you had recently upgraded your root cause analysis process in response to previously identified weaknesses in your corrective action processes, the root cause analysis for the DB-50 breaker failures performed using the new process was inadequate for the following reasons. In May 1997, you assembled a team, and hired contractors with expertise on Westinghouse DB-50 circuit breakers to conduct a root cause analysis, using the upgraded process, of the recurring breaker failures. The root causes identified by the team were not clearly supported by the "as found" condition of the breakers. More importantly, because your root cause analysis focused on restoration of the original design basis of the breakers, and did not consider potential deficiencies in the original design, the analysis did not address all credible failure modes that could have prevented the breakers from closing. As a result, although you initiated corrective actions in July 1997 based on the results of the team's root cause analysis, additional breaker failures occurred in August 1997 and October 1997.
>
> "The potential safety consequences of the DB-50 breaker failures are significant because approximately 60 DB-50 breakers are installed at Indian Point 2 and are used to provide power to safety-related loads, including the containment spray pumps, auxiliary boiler feedwater (AFW) pumps, residual heat removal pumps, and safety injection pumps. In many cases, these breakers are relied upon to close automatically, such as in response to a safety injection signal or upon the occurrence of a loss of offsite power. Failure of the breakers to close on demand would require

[21] NRC Information Notice 98-38, "Metal-Clad Circuit Breaker Maintenance Issues Identified By NRC Inspections," October 15, 1998.

operator action to reset and manually reclose the breaker to restore the equipment to service. Therefore, given the potential safety consequences of the breaker failures, as well as your continuing difficulties in implementing effective corrective action processes, this violation is also classified at Severity Level III in accordance with the Enforcement Policy."[22]

Less than a year after the plant had to be shut down due to problems with DB-50 breakers, another very similar failure occurred:

> Westinghouse 480V Breaker DB-50 failed to close during an attempt to start 21 AFP from the central control room. "The cause of failure was due to spalling or breaking-away of surface coating on the pivot pin and possibly the bushing (pivot pin hole) of the inertia latch. The fragments of the coating accumulated on the surfaces of the pin and the bushing reducing the clearance between the pivot pin and the pushing. The reduction in clearance resulted in binding of the inertial latch. This inertial latch binding prevented the latch from resetting to its normal position and prevented the breaker from closing."[23]

Two weeks after this failure, the failure of an output breaker on an emergency diesel generator at IP2 was reported to the NRC:

> "On 07/21/98, during the performance of the emergency diesel generator (EDG) load test, the Westinghouse Model DB-75 output breaker EDG-2053-005 (Serial #880.715-3), which connects the EDG to its 480 VAC bus, would not close. A second attempt was made to close the breaker and again the breaker did not close. The breaker was removed and thereafter examined using high-speed photography. It was observed that the trip bar operation was hanging up. The exact cause of the trip bar malfunction was not initially identified so the mechanism was removed. During further investigation, the trip bar latch and trigger were found to bind on occasion due to rough edges on the faces. Comparisons were made to other breaker mechanisms, and these mechanisms could not be made to hang up in this area.
>
> During the inspections of the remaining DB-75 breakers, one additional breaker was found to exhibit the same binding problem. This was EDG breaker 2053-006 (Serial #880.715-1). This breaker was of the same series as the other breaker, which may indicate a manufacturer's defect. No other breaker in the same series was examined but did not exhibit the same problem."[24]
>
> *<u>Potential Problem</u>: The root cause for the 23 EDG output breaker failure during the August 31, 1999, event at IP2 is personnel error in the overcurrent protection setting. According to the plant's owner, a post-calibration test procedure which is commonly used throughout the nuclear industry was not being used at IP2.[25] The litany of breaker problems in recent years at the site provided ample opportunities to benchmark site practices against industry norms, yet those opportunities were wasted.*

The safety implications of this issue, if valid, are significant. According to the plant's owner, the emergency diesel generators are the third, the DC buses the sixth, and the 480 volt safety buses the ninth

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[22] Mr. Paul H. Kinkel, Vice President - Nuclear Power, Consolidated Edison Company of New York, Inc. Notice Of Violation and Proposed Imposition of Civil Penalties - $110,000 (NRC Inspection Report Nos. 50-247/97-13; 97-15; and 98-02 and Investigation Report No. 1-97-038), July 6, 1998.

[23] James S. Baumstark, Vice President – Nuclear Engineering, Consolidated Edison Company of New York, Inc., to NRC, September 11, 1998, "10 CFR Part 21 Written Notification"

[24] Nuclear Regulatory Commission, Daily Event Report No. 34836, "10 CFR 21 Report Regarding Westinghouse DB-75 Circuit Breakers," September 25, 1998.

[25] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999.

most important systems in preventing reactor core damage at Indian Point 2.[26] The output breaker problem on August 31, 1999, ultimately caused the loss of 23 EDG, 24 DC Bus, and 480 volt safety bus 6A. The NRC has already determined safety breaker problems to have considerable safety significance in the enforcement action they took against this licensee last year. The breaker problems represent a common-mode failure mechanism that has the potential for disabling emergency equipment and backup emergency equipment.

Issue 3 – Apparent Unreliability of Emergency Diesel Generators

The reactor at Indian Point Unit 2 automatically shut down at 2:30pm on August 31, 1999. Shortly after the reactor tripped, an undervoltage condition was sensed on the 480 volt safety buses. This caused all three emergency diesel generators (EDGs) to automatically start and to connect to their associated 480 volt safety buses. However, the output breaker for one of the diesel generators (23 EDG) re-opened immediately after closing to connect that EDG to its safety bus (6A). Power to 480 volt safety bus 6A was restored around 1am on September 1, 1999 when 23 EDG was re-connected.[27]

Another emergency diesel generator failure occurred on November 29, 1998:

> "During a monthly surveillance on the EDGs, the 21 EDG failed the surveillance when a fuel oil supply line failed. No environmental problem occurred as a result of the fuel oil spill. The oil was contained and cleaned up. The LCO required that the other two EDGs be verified operable, which they were. The ESF classification was based on the EDG failing the surveillance."[28]

Two other emergency diesel generator failures occurred on or after July 21, 1998:

> "On 07/21/98, during the performance of the emergency diesel generator (EDG) load test, the Westinghouse Model DB-75 output breaker EDG-2053-005 (Serial #880.715-3), which connects the EDG to its 480 VAC bus, would not close. A second attempt was made to close the breaker, and again the breaker did not close. The breaker was removed and thereafter examined using high-speed photography. It was observed that the trip bar operation was hanging up. The exact cause of the trip bar malfunction was not initially identified so the mechanism was removed. During further investigation, the trip bar latch and trigger were found to bind on occasion due to rough edges on the faces. Comparisons were made to other breaker mechanisms, and these mechanisms could not be made to hang up in this area.
>
> During the inspections of the remaining DB-75 breakers, one additional breaker was found to exhibit the same binding problem. This was EDG breaker 2053-006 (Serial #880.715-1). This breaker was of the same series as the other breaker, which may indicate a manufacturer's defect. No other breaker in the same series was examined but did not exhibit the same problem."[29]

Thus, IP2 experienced at least four EDG failures, including at least one failure upon demand, in the past 13 months.

> "The licensee has calculated a minimum acceptable station blackout duration of 8 hours based on an offsite power characteristic group of 'P3' an emergency ac (EAC) configuration group 'A'

[26] Consolidated Edison, "Indian Point 2 Recovery Plan," Revision 0, September 13, 1999.
[27] Nuclear Regulatory Commission, Preliminary Notification of Occurrence PNO-I-99-040, September 1, 1999.
[28] Nuclear Regulatory Commission, Daily Event Report No. 35086, "One of Three Emergency Diesel Generators is Out of Service Putting the Plant in a 7 Day LCO," November 29, 1998.
[29] Nuclear Regulatory Commission, Daily Event Report No. 34836, "10 CFR 21 Report Regarding Westinghouse DB-75 Circuit Breakers," September 25, 1998.

(which was based on one out of three available Emergency Diesel Generators (EDGs) required to achieve hut shutdown conditions), and EDG target reliability of 0.95."[30]

Potential Problem: IP2 is licensed with an 8 hour station blackout coping duration that was based, in part, on an emergency diesel generator reliability of 95 percent. Actual performance of the EDGs may now be less than 95 percent..

The safety implications of this issue, if valid, are significant. The emergency diesel generators are the primary source of electricity for emergency equipment if the plant's connection to the electrical grid is lost for a prolonged period (i.e., more than two hours). According to the plant's owner, the emergency diesel generators are the third most important system at IP2 in preventing reactor core damage, more essential than the next three systems combined.[31]

Issue 4 – Potentially Unjustified License Amendment for Undervoltage and Degraded Voltage Relay Surveillance Intervals

The reactor at Indian Point Unit 2 automatically shut down at 2:30pm on August 31, 1999. Shortly after the reactor tripped, an undervoltage condition was sensed on the 480 volt safety buses.

According to the plant's owner, the undervoltage condition was caused by the tap changer on the station auxiliary transformer being in manual instead of in automatic as required by the plant's licensing basis. When the plant tripped on August 31, 1999, its electrical loads automatically transferred from internal power supplies to external sources. As known to occur, the 480 volt bus voltage dropped. Had the tap changer on the station auxiliary transformer been in automatic, the voltage reduction would have been recovered in time to prevent the undervoltage condition from triggering the start of the emergency diesel generators.[32]

A change authorized by the NRC in 1994 may have contributed to the tap changer configuration problem remaining undetected:

> "The licensee has proposed to extend the surveillance interval from 18 to 24 months for the Loss of Power Undervoltage and Degraded Voltage Relays. These relays protect the 480 volt buses under conditions of complete loss of power and degraded voltage conditions and provide an alarm in the central control room when the voltage falls to approximately 90%. In addition the undervoltage relays provide a station blackout start signal for the steam driven auxiliary feedwater pumps in the Auxiliary Feedwater System."[33]

Potential Problem: It is possible that the problem which caused the tap changer configuration error which directly caused the undervoltage condition during the August 31, 1999, event at IP2 would have been identified – and fixed – during a surveillance test. If so, the reduction of the testing interval in 1994 also reduced safety margins at the plant, contrary to what the licensee stated at that time..

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[30] Francis J. Williams, Jr., Project Manager, Nuclear Regulatory Commission, to Stephen E. Quinn, Vice President – Nuclear Power, Consolidated Edison Company of New York, Inc., "Staff Evaluation of Indian Point Nuclear Generating Station Unit No. 2, Response to the Station Blackout Rule," Section 2.1 – Station Blackout Duration, November 21, 1991

[31] Consolidated Edison, "Indian Point 2 Recovery Plan," Revision 0, September 13, 1999.

[32] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999.

[33] Francis J. Williams, Jr., Project Manager, Nuclear Regulatory Commission, to Stephen E. Quinn, Vice President – Nuclear Power, Consolidated Edison Company of New York, Inc., "Issuance of Amendment for Indian Point Nuclear Generating Unit No. 2," December 20, 1994.

The safety implications of this issue, if valid, are significant. According to the plant's owner, the 480- volt safety buses are the ninth most important system at IP2 in preventing reactor core damage.[34] The tap changer configuration error directly caused an undervoltage condition on all three 480 volt safety buses and indirectly caused the de-energization of one of those vital buses.

Issue 5 – Apparent Errors and Non-Conservatisms in Individual Plant Examination

In August 1992, Consolidated Edison submitted an Individual Plant Examination (IPE) for IP2 to the NRC.[35] An IPE is a plant-specific assessment of the potential for reactor core damage and containment failure for a large number of potential accident sequences. In August 1996, the NRC issued its evaluation of the IP2 IPE.[36] The NRC's evaluation contains the following statements and conclusions which appear to be invalidated by the August 31, 1999, event:

> Statement: "Three gas turbines are available to supply power to the Unit 2 equipment in the event of a loss of offsite power and coincident emergency diesel generator (EDG) failure."
>
> *Potential Problem: The gas turbines may have been available, but they were not used to supply power to Unit 2 equipment following an undervoltage condition on a safety bus and a coincident EDG failure.*
>
> Conclusion: The chances of a motor-drive auxiliary feedwater (MDAFW) pump failing to start are 1.1E-2 per year (or one in 90.9 years) and the chances of a MDAFW pump failing to run are 9.2E-5 per year (or one in 10,869.6 years).
>
> *Potential Problem: Depending on how one classifies the August 31, 1999, event, one of the motor-driven auxiliary feedwater pumps, namely 23 AFW, either failed to start or failed to run.*
>
> Conclusion: The chances of the turbine-driven auxiliary feedwater (TDAFW) pump failing to run are 2.1E-3 (or one in 476.2 years).
>
> *Potential Problem: When 24 Battery discharged, the flow regulatory valve for one of the two steam generators supplied by the turbine-driven auxiliary feedwater pump lost power and failed to the fully open position. The IP2 operators were forced to manually stop the TDAFW pump because it was in a run-out condition[37] Thus, the TDAFW pump failed to run.*
>
> Conclusion: The chances of a 480V or 13.8 kV circuit breaker failing to remain closed is 7.2E-7 per year (or one in 1,388,888.8 years).
>
> *Potential Problem: The output breaker for 23 EDG closed and then tripped (i.e., failed to remain closed). The 480 volt breaker problems experienced at IP2 between 1997 and 1999 provide failure consequences identical to that of a breaker failing to remain closed. The difference between a breaker that fails to close due to binding and a breaker that closes but fails to remain closed is merely semantics.*

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[34] Consolidated Edison Company of New York, Inc., Presentation to Nuclear Regulatory Commission, September 14, 1999.

[35] Consolidated Edison Company of New York, Inc., Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station, August 1992.

[36] Barry Westreich, Acting Project Manager, Nuclear Regulatory Commission, to Stephen E. Quinn, Vice President – Nuclear Power, Consolidated Edison Company of New York, Inc., "Staff Evaluation of Indian Point Nuclear Generating Station Unit No. 2 Individual Plant Examination," August 14, 1996.

[37] Private Communication with John Rogge, Branch Chief, Nuclear Regulatory Commission, September 14, 1999.

- Conclusion: The chances of an AC bus fault are 4.6E-7 per year (or one in 2,173,913.0 years).

  Potential Problem: 480 volt AC safety bus 6A de-energized shortly after the reactor trip on August 31, 1999, due to undervoltage coincident with emergency diesel generator failure.

  Conclusion: The chances of an emergency diesel generator failing to start are 3.1E-3 per year (or one in 322.6 years) and the chances of an EDG failing to run are 4.2E-3 (or one in 238.1 years).

  Potential Problem: 23 EDG started but failed to supply electricity to 480 volt safety bus 6A.

  Conclusion: The chances of a high head safety injection (HHSI) pump failing to start are 9.7E-3 (or one in 103.1 years) and the chances of a HHSI pump failing to run are 3.4E-5 (or one in 29,411.8 years).

  Potential Problem: When 480 volt safety bus 6A and 24 DC Bus were de-energized, one of the HHSI pumps was disabled.

  Conclusion: The chances of a component cooling water (CCW) pump failing to start are 1.0E-2 (or one in 100 years) and the chances of a CCW pump failing to run are 1.3E-5 (or one in 76,923 years).

  Potential Problem: When 480 volt safety bus 6A and 24 DC Bus were de-energized, one of the CCW pumps was disabled.

The safety implications of this issue, if valid, are considerable because the plant's owner and the NRC rely on the results from the IPE to focus inspection efforts and to schedule repairs. If the IPE results are non-conservative, these prioritization efforts may be improperly allocating resources.

TIMELINE		
Date	**Event**	**Source**
73/09/28	AEC issues operating license for Indian Point Unit 2 (IP2)	www.nrc.gov/AEOD/pib/reactors/247
80/04/23	Con Ed informs NRC of design and licensing bases for IP2's station batteries	Con Ed Letter
91/11/21	NRC issues Safety Evaluation Report for IP2 Station Blackout	NRC SER
92/08	IPE submitted to NRC	Con Ed IPE
93/11/30	IP2 informs NRC that all three gas turbines were demonstrated by test to start and load within one hour	Con Ed Letter
94/12/20	NRC issues license amendment increasing surveillance interval for undervoltage relays from 18 to 24 months	NRC Letter
97/10/14	IP2 shut down due to concerns about operability of Westinghouse DB-50 circuit breakers	NRC Info Notice No. 98-38
98/07/06	NRC imposes $110,000 fine on IP2 for violations including the DB-50 circuit breaker problems	www.nrc.gov Enforcement page
98/09/01	Inadvertent station blackout experienced while reactor was shut down	LER 98-013-00
98/09/25	IP2 submits Part 21 report to NRC about problems with EDG output breakers (Westinghouse DB-75 circuit breakers)	DER 34836
98/11/19	Annunciators disabled	DER 35059
98/11/29	21 EDG failed during test when fuel oil supply line broke	DER 35086
99/08/31 14:30	Automatic reactor trip	DER 36104
99/08/31 14:30+	Undervoltage on a 480V AC safety bus causes all three emergency diesel generators to start	PNO-I-99-040
99/08/31 14:30+	23 EDG output breaker trips causing 480V AC safety bus 6A to be de-energized	PNO-I-99-040
99/08/31 14:30+	Motor-driven 23 AFW pump fails to run due to bus 6A being de-energized – operators manually start turbine-driven 22 AFW pump	PNO-I-99-040
99/08/31 ≈21:40	24 DC battery discharged causing loss of 24 Instrument Bus	PNO-I-99-040
99/08/31 21:55	Unusual Event declared based on loss of 75% of control room annunciators	DER 36107
99/08/31 ≈01:00	23 EDG connected to 480V AC Safety Bus 6A	PNO-I-99-040
99/09/01 01:57	Annunciators reported restored	DER 36107
99/09/01 03:43	Unusual Event reported exited	DER 36107
99/09/01 ≈06:00	Loads restored to 480V AC Safety Bus 6A	PNO-I-99-040
99/09/01 ≈22:00	Normal power supply connected to 480V AC Safety Bus 6A – 23 EDG secured	PNO-I-99-40A