A. Alan Blind
Vice President

Consolidated Edison Company of New York, Inc.
Indian Point Station
Broadway & Bleakley Avenue
Buchanan, NY 10511
Telephone (914) 734-5340
Fax: (914) 734-5718
blinda@coned.com

February 1, 2001

Re: Indian Point Unit No. 2
Docket No. 50-247
LER 2001-001-00
NL-01-010

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop PI-137
Washington, DC 20555-001

The attached Licensee Event Report 2001-001-00 is hereby submitted in accordance with the requirements of 10 CFR 50.73.

Sincerely,

A. Alan Blind

Attachment

cc: Mr. Hubert J. Miller
Regional Administrator - Region I
US Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. Patrick D. Milano, Senior Project Manager
Project Directorate I
Division of Licensing Project Management
US Nuclear Regulatory Commission
Mail Stop O-8-C2
Washington, DC 20555

Senior Resident Inspector
US Nuclear Regulatory Commission
PO Box 38
Buchanan, NY 10511

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NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION
(6-1998)

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001

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TITLE (4)
Turbine Trip During Startup Results in Auxiliary Feedwater System Actuation

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL	REVISION	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
										05000
01	02	2001	2001	-001-	00	02	01	2001	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
POWER LEVEL (10)	006		20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
			20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER - Specify in Abstract below or in NRC Form 366A
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Richard Louie, Licensing Engineer	(914) 734-5678

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On January 2, 2001, at about 1524 hours, during preparations for main turbine start-up and with the reactor at 6.5 percent power, a turbine trip occurred due to high water level in 21 Steam Generator. This event resulted in the initiation of the Auxiliary Feedwater System, which is an Engineered Safety Feature (ESF) actuation. Prior to the turbine trip, control room operators had started 21 Condensate Pump in accordance with Plant Operating Procedure (POP) 1.3, "Plant Start-up from Zero Power Condition to Full Power Operation," to compensate for increased feedwater demand during the main turbine start-up and subsequent power escalation. As designed, the trip signal also resulted in the closure of the main feedwater pump discharge valves, and the steam generator blow down isolation valves. The cause for the high steam generator water level condition was attributed to an off-normal secondary system condition resulting in low main feed pump suction pressure, along with untimely operator action. During this event no Technical Specification requirements or safety limits were exceeded.

In accordance with 10CFR50.72(b)(2)(ii), the NRC was notified of this event at 2205 hours on January 2, 2001; however, this notification was not made within the required time. This report is being made pursuant to 10CFR50.73(a)(2)(iv) as an event resulting in an Engineered Safety Feature (ESF) actuation.

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PLANT AND SYSTEM IDENTIFICATION

Westinghouse 4-Loop Pressurized Water Reactor

EVENT IDENTIFICATION

Turbine Trip During Startup Results in Auxiliary Feedwater System (an engineered safety feature) Actuation

EVENT DATE

January 2, 2001

REFERENCES

Condition Reporting System Number(s): 200100048, 200100044, 200101075, 200100200, 200100361, 200100855

PAST SIMILAR EVENTS

LER 1985-010, 85-014, 95-001, and 96-016

EVENT DESCRIPTION

On January 2, 2001, at approximately 1500 hours, with reactor power at approximately 6.5 percent and high pressure steam dumps in automatic, during preparations for a main turbine start-up, control room operators started 21 Condensate Pump. 21 Condensate Pump was the second condensate pump placed in service and was required to be started by Plant Operating Procedure (POP) 1.3, "Plant Start-up from Zero Power Condition to Full Power Operation," to satisfy increased feedwater demand during the main turbine start-up and subsequent power escalation. In addition, plant conditions were such that starting the 21 Condensate Pump was initiated for purposes of increasing an observed low main boiler feed pump suction pressure. The condensate pump start-up increased the 22 Main Boiler Feed Pump discharge pressure approximately 50 psig. The low flow feed regulating valves were utilized to supply feedwater to the steam generators, and were open approximately 65 percent to 80 percent. Other existing plant conditions included 21 Main Boiler Feed Pump operating at approximately 1200 rpm with the discharge valve closed and in a recirculating line-up.

Following the start of the second condensate pump, water levels immediately started increasing in all four steam generators. Steam generator level increased from approximately 30 percent to 50 percent. Condensate temperature was approximately 70 degrees. The steam generator level increase was recognized by the control room staff, and in response they moved the low flow feed regulating valves in the closed direction, to approximately 10 percent open, from their initial position.

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When the steam generator level reached 60 percent, the Control Room Supervisor directed the low flow feed regulating valves be closed completely. In addition, the speed of the 22 Main Boiler Feed Pump was decreased in an attempt to control the steam generator level increase. However, the cold feedwater already fed into the steam generators and then heated resulted in a steam generator level swell to the steam generator high level trip set point (73 percent Narrow Range). As a result of reaching the high-level trip setpoint in 21 Steam Generator, the 22 Main Boiler Feed Pump tripped and its associated discharge valve closed (ESF valve). Also, the main turbine automatically tripped on high steam generator level. The Auxiliary Feedwater System (ESF) automatically actuated on closure of the main boiler feed pump discharge valve and the trip of the main boiler feed pump and the steam generator blowdown isolation valves closed (ESF valves). This is considered an actuation of ESF components. The 21 Main Boiler Feed Pump continued to run as its discharge valve was already closed (per system design the automatic trip function of the pump was not armed).

To respond to the Main Turbine trip, the control room staff entered Abnormal Operating Instruction (AOI) 26.4.6, "Main Turbine Trip Without a Reactor Trip." The procedure requires that the operators decrease power to less than 3 percent if auxiliary feedwater is the only source of feed to the steam generators. The control room staff began inserting control rods to decrease reactor power to less than 3 percent to be within the capability of the motor driven auxiliary feedwater pumps and to reduce the rising reactor coolant average temperature. Control rods were initially inserted 24 steps and subsequently inserted an additional 5 steps to further reduce reactor power. The Operator inserted the control rods to a known position from earlier in the day when reactor power level was at approximately 2 percent. The condenser steam dumps were taken to manual and closed. From plant computer data, following the initial rod insertion, the atmospheric relief valve(s) exceeded their setpoint (1020 psig) and opened to reduce steam generator pressure. As reactor coolant temperature increased again, the Control Room Supervisor directed opening the atmospheric relief valves to decrease steam generator pressure from 1020 psig to 1000 psig. Reactor power decreased to approximately 1 percent based on the indication monitored by the control room staff. During this transient the reactor coolant temperature increased to a maximum of approximately 552F, decreased to a minimum of 543F, and finally stabilized at approximately 547F. The Shift Manager, via the Control Room Supervisor, directed the Reactor Operator to withdraw control rods to return power to approximately 2 percent. Subsequent control rod withdrawals were performed in accordance with AOI 26.4.6 to return reactor coolant average temperature to the no-load value. The increase of reactor power was conducted while carefully monitoring reactor power and average temperature. Reactor power was stabilized at approximately two percent and average reactor coolant temperature was stabilized at 547F.

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EVENT ANALYSIS

Subsequent analysis of this event indicated that the possibility of a reactivity excursion following the turbine trip should be examined. To stabilize reactor power after the turbine trip at 1524 hours, the control rods were inserted between 1524 and 1526 hours and subsequently withdrawn after 10 minutes. The transient was essentially over at about 1540 hours when reactor power was stabilized at approximately one percent power. The subsequent control rod withdrawal to return the reactor coolant temperature to the no-load value and the reduced temperature caused a slight reactivity overshoot and returned the system to stable conditions at 1545 hours. The reactor was not taken below the point of adding heat (POAH) and thus was not taken net subcritical.

The Reactor Engineering Section used the lowest reactor power level achieved during the event as measured by the plant computer and compared this power to the power level measured during physics testing at the point of adding heat by the reactivity computer. The comparison indicated that reactor power remained well above the point of adding heat. Therefore, it was concluded that during the transient, power did not go below the point of adding heat. The minimum power for nuclear heat is 0.3 percent and the minimum power observed during the transient was greater than 0.5 percent.

Interviews of the operating crew indicated that prior to the trip, main boiler feed pump suction pressure was abnormally low, and that 22 Main Boiler Feed Pump speed demand was higher than expected.

The plant-specific simulator was then utilized to attempt to re-create the event. One condition assumed was that the discharge valve on the first condensate pump was either never fully opened, throttled closed, or had become separated from its stem. A plant field operator was asked how far open (percentage) the discharge valve is at 13 turns open. The field operator indicated that the valve was 10-15 percent open. The plant specific simulator was set up with the condensate pump discharge valve at 19 percent open, resulting in a low (approximately 300 psig) suction pressure. When the second condensate pump was started in this alignment, the simulator response was nearly identical to that of the plant. The apparent cause for the lower than expected suction pressure to the main boiler feed pump was the simultaneous occurrence of: the 21 Main Boiler Feed Pump running at 1200 rpm with its recirculating valve open, a flow control valve in the Condensate System, FCV-1113, isolated for repair, the bypass around FCV-1113 throttled open, and excess condensate level control valve LCV-1129 open recirculating the contents of the condensate storage tank. Based upon subsequent analysis and evaluation, it is concluded that the low suction pressure condition, combined with the start of the second condensate pump, initiated the steam generator level transient.

Following the start of the second condensate pump, the operating crew did not initially compensate for the increased feed water flow to the steam generators because they concluded that the steam generator level was increasing at a sufficiently slow rate that it could be addressed subsequently.

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Engineering agreed with conclusions that the swell in the steam generator level following the closure of the low flow regulating valves was due to the heating and subsequent expansion of the feedwater

Following operator interviews, simulator runs, and review of the event time line, the root cause of the event was determined to be an off-normal secondary system condition that resulted in low main boiler feed pump suction pressure during the start of the second condensate pump. These circumstances, in conjunction with untimely operator action, caused a turbine trip on high steam generator level.

Contributing factors have been identified, as follows:

- When the operating crew reached the procedural step to start a second condensate pump, the pump was started without questioning the cause of the low main boiler feed pump suction pressure.

- Procedural inconsistencies between the abnormal operating instruction "Turbine Trip without Reactor Trip," (AOI 26.4.6) and station reactivity management requirements [Station Administrative Order (SAO)-442 and Operations Administrative Directive (OAD)-39] provided unclear guidance to the operating crew regarding withdrawal of control rods during transient conditions.

- Less than adequate procedure adherence, which resulted in manual operation of the steam dump system, thereby exacerbating the transient. The condenser steam dumps were transferred to manual and closed early in the event. This occurred due to a communications error between the Control Room Supervisor and Reactor Operator. With these steam dumps in manual, the resultant steam generator pressure increase lifted the atmospheric relief valves at approximately 1020 psig. The operators saw the steam generator pressure increase following the initial lift of the atmospheric relief valve and took manual control of the atmospheric relief valves. Manual control of the atmospheric relief valves resulted in undershooting the desired reactor coolant system temperature. Additional manual manipulations of the atmospheric relief valves subsequently stabilized reactor coolant system temperature at the no-load value.

- Perceived pressure to return the unit to service may have adversely affected the operators' judgment by influencing them to accept less than adequate plant conditions during preparations for main turbine startup. Discussions with control room operators, as well as daily observations by Quality Assurance indicated that once physics testing had ended there was a strong desire by station management to bring the outage to a close.

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EVENT SAFETY SIGNIFICANCE

At all times during the events described, actions of the licensed operators maintained the reactor core and equipment within all Technical Specification requirements and safety limits. The reactor remained above the point of adding heat throughout the event. Plant procedures defined the event as a "significant reactivity management event" since it resulted in a reactor power change greater than 2 percent.

Positive reactivity was simultaneously inserted into the reactor core during the transient by two means. The two means of positive reactivity insertion were the decreasing reactor coolant average temperature and the methodical withdrawal of control rods. Reactor coolant average temperature was decreasing due to the following:

- 21 Main Boiler Feed Pump continuing to run on recirculation using steam from the steam generators,
- the existence of the cold water injected into the steam generators by first, the increased feed flow and second, the actuation of the auxiliary feed system,
- the operation of the steam relief system in manual and valves open, and
- initial control rod insertion.

The plant transient that resulted from the steam generator level transient resulted in the automatic start of the auxiliary feed pumps. The Auxiliary Feedwater System performed as designed. This event did not result in any radioactive releases nor did it result in any personnel injury or damage to plant equipment.

50.72 Late Report Notification

In accordance with 10CFR50.72(b)(2)(ii), this event is reportable as a four-hour report since it resulted in a manual or automatic actuation of an Engineered Safety Feature (ESF). Based upon the approximate time of the event, 1500 hours, the NRC was required to be notified by 1900 hours. However, an appropriate notification was not made until 2205 hours. Initially, operations personnel who reviewed this event for reportability did not believe that the start of the auxiliary feedwater (AFW) pumps comprised an ESF actuation. However, when the start of the motor-driven AFW pumps is associated with a trip of the main feedwater pumps, Technical Specification Table 3.5-3 provides that such circumstances are to be considered as an ESF actuation. The apparent cause for the delayed notification is attributed to operations personnel failing to view the start of the AFW pumps in the context of the overall situation. At the time, the focus of the reportability review was limited to the initiating event (i.e., feedwater isolation) rather than the entire sequence of actions associated with the isolation. Subsequent to the initial reportability review it was determined that a 50.72 notification to the NRC was necessary, however by such time the four-hour requirement had been exceeded.

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CORRECTIVE ACTIONS

Immediate corrective actions included the following:

- Power escalation was put on administrative hold.
- The condensate discharge valves were verified to be fully open for the plant configuration.
- Plant procedure revisions were made to reconcile inconsistencies and facilitate ease of operator understanding.
- The Operations Manager completed crew briefings on the event with all watch crews, and Watch Engineers were directed to brief the crew on current reactivity equivalents at the start of each shift.
- Procedures to be used for the balance of the start-up, considering the lessons learned, were re-validated on the plant-specific simulator.
- A "stand-down" was held to critique the event with station personnel.
- Cautions were added to POP 1.3, "Plant Startup from Zero Power Condition to Full Power Operation," expressly advising that the starting of a second condensate pump results in increased feed flow that requires heightened operator attention.
- OAD-39, "Reactor Power Control," was reviewed and revised to more conform to industry standards of avoiding control rod withdrawal during off-normal events. OAD-15, "Policy for Conduct of Operations," was revised to direct operators under normal circumstances to maintain controllers and systems in automatic control.
- AOI 26.4.6, "Abnormal Operating Instructions for Turbine Trip Without Reactor Trip," and AOI 21.1, "Loss of Feedwater Pumps," were revised to include a requirement to trip the reactor if a turbine trip and loss of feedwater occurs with reactor power greater than 4 percent so as to reduce challenges associated with reactivity management. AOI 26.4.6 was also revised to comply with station expectations to not withdraw control rods during an off-normal secondary transient.
- The "pressure to perform" issues and their relationship to station management's expectations for procedural adherence were reviewed with all operators in an open interactive forum.

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Additional corrective actions to be completed include the following:

- SAO-442, "Reactivity Management," will be enhanced to better reflect current industry practices and standards regarding event classification.
- Additional guidance and clear steps for startup and operation of a second and third condensate pump that are contained in System Operating Procedure (SOP) 20.2, "Condensate Pump Operation," will be added to address system hydraulic response.
- Plant-specific simulator scenarios will be developed to increase operator awareness and improve response in circumstances of off-normal secondary system conditions, and for the purpose of enhancing operator response to conditions where there is a loss of turbine without a reactor trip and loss of feedwater.
- Operations management will provide training to control room staff on changes made to procedures (OAD - 15 and OAD - 39) as a result of this event.
- Watch Engineers, Control Room Supervisors, and Shift Managers will be provided further training on event reporting corresponding to the requirements of 10CFR50.72.

These corrective actions will be completed by May 31, 2001.