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NUCLEAR REGULATORY COMMISSION
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April 28, 2000

AIT for IP2 Feb 15th Event
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Mr. A. Alan Blind
Vice President - Nuclear Power
Consolidated Edison Company of
New York, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenues
Buchanan, NY 10511

SUBJECT: NRC AUGMENTED INSPECTION TEAM - STEAM GENERATOR TUBE FAILURE - REPORT NO. 05000247/2000-002

Dear Mr. Blind:

On March 3, 2000, the NRC completed an Augmented Inspection Team (Team) inspection at the Indian Point Unit 2 (IP2) Station. The enclosed report (Enclosure 1) presents the results of that inspection.

The Team was chartered (Enclosure 2) to review the causes, safety implications, and your staff's actions following the steam generator tube failure at IP2 on February 15, 2000. The Team reviewed the record of activities that occurred, interviewed personnel, and conducted plant walkdowns. The Team developed a sequence of events, determined the risk significance of the event, and assessed the quality of response by the plant staff and management. The cause of the tube failure was outside the scope of this inspection, and is being reviewed separately by the NRC. A summary of the Team's findings was presented at a public exit meeting on March 29, 2000. The NRC briefing slides from that meeting are provided in Enclosure 3.

The event had moderate risk significance. It involved a steam generator tube failure that resulted in an initial primary-to-secondary leak of reactor coolant of approximately 146 gallons per minute, and required an "Alert" declaration (the second level of emergency action in the NRC required emergency response plan). The event resulted in a minor radiological release to the environment that was well within regulatory limits. The Team noted that no radioactivity was measured off-site above normal background levels, and determined that the event did not impact the public health and safety.

Your staff acted to protect the health and safety of the public. Specifically, the operators promptly and appropriately took those actions in the emergency operating procedures to trip the reactor, isolate the affected steam generator, and depressurize the reactor coolant system. Additionally, the necessary event mitigation systems worked properly. Notwithstanding the above, the Team identified problems in several areas including operator performance, procedure quality, equipment performance, technical support, and emergency response. These problems challenged the operators, complicated the event response, and delayed the plant cooldown.

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Several of the identified equipment problems such as a degraded steam jet air ejector steam supply valve, and an isolation valve seal water system design deficiency were long standing (Section 4.1). Some of the emergency plan implementation problems were similar to previously identified problems in this area; for example, technical support center personnel did not consistently anticipate plant problems and make timely recommendations to the operators (Section 4.3), which was also a finding during the September 1999 emergency preparedness exercise. The failure to correct these problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station. The Team recognized that, prior to the event, your staff was in the process of implementing a station improvement program. This event demonstrated the need for continuous management attention to planned improvements to ensure they are timely and effective.

The Team reviewed the activities of your Event Investigation Team (EIT), and noted that while some of the preliminary assessments appeared similar to the Team findings, the EIT activities and proposed corrective actions were not finalized prior to the end of the inspection period. Therefore a final assessment of your planned corrective activities could not be reached. The NRC plans to review selected corrective actions prior to the plant re-start.

In accordance with NRC procedures, the AIT charter did not include the determination of compliance with NRC rules and regulations or the recommendation of enforcement actions. Those aspects will be addressed in subsequent inspections or reviews.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

HJMiller

Hubert J. Miller
Regional Administrator

Enclosures:
1. NRC Augmented Inspection Report No. 05000247/2000-002
2. NRC Augmented Inspection Team (AIT) Charter
3. NRC Briefing Slides - March 29, 2000, Exit Meeting

SUMMARY

Indian Point Unit 2 Station
NRC Inspection Report 50-247/00-02

An NRC Augmented Inspection Team (Team) reviewed the causes, safety implications, and associated licensee actions in response to a steam generator (SG) tube failure event that occurred on February 15, 2000.

Background

Indian Point Unit 2 has four steam generators, which are designated as the number 21, 22, 23 and 24 SGs. Each steam generator has 3260 U-shaped tubes. Reactor coolant (the "primary" side) passes through the tubes, heating the normally non-radioactive water in the steam generator (the "secondary" side) to produce steam which is used to operate the main turbine. After the steam passes through the main turbine, it is condensed and the water is pumped back to the steam generator to repeat the cycle. A cutaway view of a typical steam generator and a diagram depicting the primary and secondary flowpaths are included as Attachment 1 to this report.

On February 15, 2000, one of the tubes in the No. 24 steam generator failed, allowing reactor coolant into the steam generator. Until the affected steam generator was isolated, the contaminated water mixed with the steam and water in the secondary plant. Actions to mitigate a steam generator tube failure included shutting down the reactor, isolating the affected steam generator, and cooling down and depressurizing the reactor coolant system to prevent leakage into the steam generator.

Event Overview/Significance

The licensee performed the necessary actions to mitigate this event, including shutdown of the reactor, identification and isolation of the faulted SG, cooldown of the reactor coolant system (RCS), declaration of the Alert, and staffing of the emergency response organization (ERO). The Team noted that no radioactivity was measured off-site in excess of normal background levels and determined that the event did not impact the health and safety of the public. Necessary event mitigation systems worked properly. Although there was no impact on public health and safety, the event had moderate risk significance and required the declaration of an Alert.

The Team identified performance problems in several broad areas that challenged operators, complicated the event response, delayed achieving the cold shutdown condition, and impacted the radiological release. The problems summarized in Section 3.0, involved: operator performance, procedure quality, equipment performance, technical support, and emergency response.

Operator Performance

The operators performed the necessary activities to mitigate this event including (Section 4.2):

- The event was promptly recognized and properly classified.
- The reactor was promptly shutdown per procedure.
- The affected steam generator was identified and isolated.
- The plant was placed in cold shutdown to terminate the event.

Procedural adherence was generally good during the event. A few minor procedural adherence issues such as not shutting a condenser vacuum pump discharge valve were identified.

Some operator performance problems were noted during the plant cooldown phase involving:

- While attempting to cooldown the RCS, the reactor operator initiated an excessive cooldown rate that exceeded procedural and Technical Specification (TS) limits. The excessive cooldown led to several conditions that complicated the subsequent event response and delayed the RCS cooldown.

- Operators were slow to recognize configuration line-up problems that prevented successful operation of the auxiliary spray system to lower RCS pressure, and delayed heat-up of the residual heat removal system.

Procedure Quality

The procedures adequately guided the initial operator response; however, several procedure problems were identified that delayed the cooldown and depressurizing of the RCS.

Equipment Performance

The necessary event mitigation systems, including the reactor protection system, auxiliary feedwater system, and the safety injection system functioned properly. However, several long-standing equipment performance problems were identified that challenged operators during this event:

- Two losses of condenser vacuum resulted from problems with the operation of the automatic steam supply pressure control valve to the steam jet air ejectors (SJAEs), and the #22 condenser vacuum pump.

- The isolation valve seal water system (IVSWS) became inoperable during the event, and required operator action and an entry into a TS Limiting Condition for Operation Action Statement.

- A containment entry was required to install a temporary nitrogen supply to the pressurizer power operated relief valve to compensate for a design deficiency. This action was required prior to placing the over-pressure protection system in-service.

- The SG leak rate monitoring equipment had been degraded for an extended period of time, and limited the amount of SG leak rate information available to the operators prior to the event.

The Team determined that the number and duration of the equipment problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station. The licensee's response to a number of the equipment problems identified during the event reflected an acceptance of "working around" rather than fixing the problem.

Emergency Response

The ERO took the necessary steps to ensure the protection of public health and safety. The operators properly classified the event, and the licensee implemented a thorough peer review of the emergency response to this event. The Team identified several emergency plan and implementing procedure problems similar to those identified by the licensee's peer review team including:

- The emergency response staff was slow to activate the emergency facilities.
- The licensee was slow to establish accountability (i.e., identify the location) of emergency response personnel.
- The emergency response data system (ERDS) was inoperable for the first several hours of the event due to a pre-existing equipment problem.
- Problems were noted in the implementation of the media response plan.
- Problems were identified involving the timeliness and quality of technical support provided to the operators.

The licensee developed and was in the process of implementing an emergency response improvement plan prior to the event.

On February 17, at 2:40 a.m., the operators removed one of the RHR heat exchangers from service. The Team identified that following this planned evolution the differential temperature between the RCS hot and cold legs reached about 90°F. This exceeded the 72°F limit specified in SOP 4.2.1. The licensee initiated CR 200001681 to review this issue.

Operator Logkeeping

The Team noted that the operator logs were not maintained throughout the event as required by the licensee's administrative procedures. Specifically, the operators did not consistently log significant plant items such as the event declaration, implementation of the emergency plan, abnormal indications, major plant evolutions, and equipment alignment changes.

Licensee Requirements for Procedural Adherence and Use

The Team reviewed OAD-33, "Procedure Adherence and Use," and noted inconsistent guidance pertaining to the requirements for allowing an operator to deviate from a written procedure. Specifically:

Section 4.4.1 was based on an American National Standard Institute Standard (ANSI N18.7-1976) and allowed operators (on their initiative) to not follow a procedure provided that the action was necessary to protect the health and safety of the public, plant personnel, or to prevent damage to plant equipment. The section also required the operator to inform the shift manager (SM), after the fact, regarding the procedural deviation.

Section 4.4.2 required the operator to obtain permission from a Senior Reactor Operator (i.e. the SM) before deviating from a procedure. This section also required that the action be taken when immediately needed to protect public health and safety. This was consistent with 10 CFR 50.54 (x) which limits departures from a license condition to emergency situations to protect public health and safety.

The Team discussed a concern with station and operations management that the guidance contained in Section 4.4.1 of administrative procedure OAD 33 could result in an improper deviation from an approved operating procedure. The licensee planned to review and revise, as necessary, all affected administrative procedures prior to restart.

4.3 Emergency Response Organization Performance

The SM correctly classified the event as an Alert using Emergency Action Level (EAL) 3.1.2 for reactor coolant leakage exceeding the capacity of one charging pump (>75 gpm). Notifications to the State of New York, the Counties of Rockland, Westchester, Putnam and Orange and the Town of Peekskill met the 15-minute time requirement as described in the licensee's Emergency Plan (E-Plan) Implementing Procedure, IP-1002.

Immediately following the event, the licensee conducted emergency facility critiques and appointed an independent review team consisting of emergency response specialists from other utilities to assess the adequacy of the ERO's performance. The post-critique report was self-critical and thorough. The identified problems, which included the independent review team findings, encompassed the broad areas of ERO mobilization, facility activation, accountability and communications and are discussed below in more detail.

The licensee's emergency facilities were not activated for approximately one hour and 40 minutes after the event declaration. Emergency Plan Figure 5.2-1 requires the minimum facility staffing to be completed within 60 minutes. Contributing factors to the failure to activate the ERO facilities within the required time included: (1) emergency response pagers were not activated by the corporate information group (CIG) for about 20 minutes after the event declaration; (2) the automated telephone notification system was not activated until 50 minutes after the event declaration because the recorded event message was incorrect and had to be re-recorded; (3) there was confusion at the security guard house as to where to send responders for accountability and facility assignments; and (4) activation of the operations support center (OSC) was delayed due to the licensee's decision to move the facility to another location for better coordination with the technical support center (TSC). The OSC was originally scheduled to be moved next to the TSC in March 2000, as part of the on-going corrective action plan to improve ERO performance.

The Team determined that the procedure and process used to activate the pagers were complex and required an excessive period of time (approximately 20 minutes) to activate the pagers. This resulted in licensee personnel having about 40 minutes to travel to the site, and activate the ERO facilities. The slow pager activation process appeared to be a significant factor in the licensee's failure to meet the facility activation requirements. The Team reviewed the monthly communication tests and found that there was no formal process for documenting pager activation problems and for ensuring that all ERO staff received the proper signal. Prior to the event, the licensee had not fully implemented the activation procedures during scheduled daytime emergency drills or exercises. The Team determined that the licensee was not aware of the pre-existing activation problems.

Accountability of onsite personnel was not completed within 30 minutes as specified in Section 6.4.1(d) of the E-Plan. The delay in completing accountability appeared to be related to an inconsistent understanding between ERO managers of the requirements for declaring that accountability was complete. Specifically, the SM completed an initial accountability check; however, the OSC Manager requested that the accountability check be re-performed since several people were identified as missing following the first check. Accountability was subsequently declared complete at about one hour and 1 minutes after the start of the event. Section 8.1.3, "Drills and Exercises," of the E-Pl committed the licensee to conduct an "off-hours" exercise once every six years. The

Team noted that the last "off hours" exercise was conducted in 1993 and did not meet this requirement. The Team determined that the failure to exercise the ERO during an "off hours" condition, as required, contributed to the accountability problem remaining undetected.

During the Alert declaration, security personnel secured the owner controlled and protected areas for establishing accountability. This included closing the main entrance gate and only granting access to oncoming ERO members. The security manager determined, however, that the Indian Point Unit 3 access gate, which is an egress to the IP2 owner control area, was not guarded until midnight and not locked until 3:00 a.m. Although this was not a procedural requirement, security personnel were expected to immediately ensure that the gate was closed. As a result, some ERO responders were not accounted for because they bypassed the main gate for the owner controlled area. The potential consequences of not securing all access points included inaccurate accountability of ERO responders and the potential for open access of the general public into the EOF. Security immediately implemented a change to Post Guidelines 5, 6 and 12 to require that the Unit 3 gate be immediately closed during an Alert and above.

At the time of the event, the licensee was in the process of implementing a transition to upgrade the TSC and OSC facilities. This transition included the development and staging of new operating procedures. Facility training was scheduled to be conducted during the months of February and March 2000. As a result, ERO personnel in the TSC and OSC were confused as to which procedures were applicable so they elected to use the current procedures along with the new (unapproved) procedures. The licensee stated that the requirements in the new procedures were similar to the existing procedures but contained improved guidance for ERO personnel. Based on this information, the Team determined that use of the new procedures should not have adversely affected the performance of ERO personnel.

Several equipment problems were found in the TSC including:

- The removal of two computer information displays from the TSC apparently caused initial confusion among technical staff personnel who reported having a difficult time accessing real-time plant operating data. Technical support personnel reported that the information display problems contributed to a delay in making an initial estimate of the 24 steam generator tube leak rate, and an incorrect determination that the SG tube leak rate significantly increased prior to the SI initiation.

- The emergency response data system (ERDS), located in the TSC, is a real-time electronic data link between the licensee's onsite computer system and the NRC Operations Center. It provides for the automated transmission of plant parameters. During the night of the event, ERDS was not operable until 3:00 a.m. The licensee is required by 10 CFR Part 50, Appendix E.IV to test the system quarterly to verify that it is available. The records for the first quarter of 2000 indicated that initial test attempts were unsuccessful due to noise on the telephone lines. The test was subsequently completed successfully using an alternate telephone line; however, the ERDS was then placed back onto the original telephone line without additional testing to ensure that it would work in this configuration. The Team concluded that the licensee failed to properly correct the identified ERDS problem prior to the event.

- 10 CFR 50.72(B)(c)3 requires that licensees maintain an open, continuous communication channel with the NRC Operations Center upon request by the NRC. At 7:00 a.m., on February 16, the NRC formally requested, via the resident inspector, that a communication link be established and continuously manned. The licensee did not establish this line in a timely manner (i.e., approximately two hours elapsed between the time of the initial request, and the establishment of a line). The delay in manning this line appeared related to a difficulty in locating the proper communications equipment.

The ERO technical staff performed well in developing a contingency plan to lower SG level through the steam generator blowdown purification system. However, the Team noted several other examples where the ERO technical staff was narrowly focused or failed to implement timely and effective corrective actions to resolve the problems that complicated the event response. Some of the specific examples included:

- The ERO technical staff in the TSC did not anticipate and help resolve the procedural, and plant configuration problems (discussed in Sections 4.1.6, and 4.2) without delaying the plant cooldown and depressurization.

- ERO technical support personnel in the TSC and OSC should have been aware of the longstanding use of the manual bypass valve to control the steam supply pressure to the main condenser SJAE. These personnel did not anticipate and recommend that the bypass valve be re-positioned to prevent the degradation in condenser vacuum (Section 4.1.3).

- ERO technical support staff in the EOF did not properly resolve two discrepant radiological survey readings that were reportedly taken external to the #24 ASDV tailpipe until the basis for not taking an additional confirmatory sample was challenged by the NRC (i.e., one survey indicated that a release had occurred, and one showed background levels).

- When the control room operators initiated SI, the condenser off-gas was re-directed from the containment to the plant vent (discussed in Section 4.2). The ERO technical support staff in the TSC did not make any recommendations to secure this release path.

- Primary boron concentration sample results did not appear to be consistently communicated well between the control room and technical support center personnel.

- The ERO technical support staff in the OSC were slow to complete the pinning of the main steam lines to protect against a possible challenge to the lines from overfilling of the #24 SG. This activity was not completed until just prior (about 5 minutes) to the approximate time when the SG was projected to overfill (discussed in Event Timeline - Attachment 1).

Section 5.2.3 of the E-Plan defined the purpose of the emergency news center (ENC). The associated implementing procedure and the Emergency News Center Response Plan defined the overall operation of the ENC, onsite responsibilities, and the process for disseminating accurate information to state, county, and local agencies and the general public. The Team determined that the Media Relations Emergency Response Plan poorly described the delegation of assignments, position responsibilities, time requirements for contacting off-site officials, and training requirements.

Based on the licensee's findings and inspector interviews, the Team determined that the oversight of the ENC was weak relative to ensuring that the E-Plan commitments would be met. Despite the fact that the ENC was successful in issuing two press releases during the event, several performance problems were identified that adversely impacted the ENC performance. These problems included:

- Facility activation was delayed since the individual with the key to the facility was filling an ERO position located in the EOF, personnel unexpectedly actuated the building security alarm during initial entry, and the available media managers had not been formally qualified.

- Technical and support personnel did not appear to have a good knowledge of their positions, and responders lacked familiarity with the specifics of the job.

- A discrepancy was noted between the information documented on an offsite notification form, and the information provided by the licensee corporate spokesperson and a press release regarding whether a radiological release had occurred.

- Proper controls had not been established to prevent unrestricted public access to the center.

- The responsibilities of the ENC Duty Officer prior to activation were not clearly defined.

- Although attempts were made, one town official was not contacted per Appendix 5 of the Media Emergency Plan due, in part, to an outdated phone list.

End of EP Section

In September 1999, the NRC evaluated the licensee's performance during an emergency exercise (as described in NRC Inspection Report 99-12) and identified several ERO performance weaknesses. The licensee subsequently developed a corrective action plan to improve ERO performance. While some of the problems identified during this event such as facility activation and accountability were new, other problems, such as the quality of ERO technical support were similar to the previously identified problems.

4.4 Radiological Release Assessment

4.4.1 General Description

The #24 SG tube leak initially resulted in a radioactive gaseous (principally noble gases) release to the turbine and condenser. During normal operation, the condenser is continually evacuated through the SJAE to the atmosphere. This normally non-radioactive exhaust pathway is monitored by a radiation monitor (R-45) prior to release to the atmosphere. The radioactive gas set off the high radiation alarm on the SJAE monitor (R-45) within one minute following the tube failure and automatically diverted the SJAE flow from the atmosphere to the reactor containment. As a result, any initial radioactive gaseous release from the SJAE to atmosphere was limited to the time it took for the valve to automatically divert flow to containment (i.e., about 45 seconds). The No. 24 SG was then isolated to limit any subsequent releases. Following the SI (Section 4.2), the condenser off-gasses were redirected from the containment back to the plant vent for the duration of this event. This created an additional minor release path as noted in Attachment 5. Attachment 5, using a simplified plant diagram, depicts the principal release paths.

As a result of the steam generator tube failure, any radioactivity that passed into the condenser affected the condensate water that was circulated back to the remaining steam generators until 7:35 p.m., when the main feedwater pumps were secured. The AFW pumps were subsequently operated to provide an unaffected feedwater source to the steam generators. Five minutes after the R-45 high radiation monitor alarmed, a control room operator manually isolated all four SG water discharge paths (steam generator blowdown) which limited the amount of radioactive release to the environment through that pathway.

On February 16, 2000, at 12:05 a.m., condenser vacuum was lost which affected the ability to reduce reactor plant pressure and temperature through the condenser. Consequently, operators opened the atmospheric steam dump valves (ASDVs) on steam generators #21, #22, and #23 in order to continue reactor plant cooldown. Opening of the ASDVs provided another potential, albeit minor since the affected SG was already isolated, unmonitored release pathway to the environment.

Condenser vacuum was restored at about 1:15 a.m., by use of the #22 condenser vacuum pump, which established another potential release pathway to atmosphere. At that time, the ASDVs were closed and steam flow to the condenser was reestablished. At 7:20 a.m., condenser vacuum was lost again and reactor plant cooldown was again effected by opening the #21, #22, and #23 ASDVs. Vacuum was restored after 92 minutes and the ASDVs were closed.

Given the potential for radioactive gaseous release from the secondary steam plant, the licensee initiated action following the event to account for all known and possible release pathways. The calculation assumed that the #24 ASDV leaked at the Class IV valve leak rate for the ten hour duration that the #24 SG pressure was elevated. The Team determined that this assumption was conservative and bounding for any actual leakage through this path.

Based on sampling and analysis, the radioactive gases released from the condenser were identified as radioactive noble gases (argon, krypton, and xenon). Releases from the ASDVs were assumed to contain the same noble gases as well as some limited radioiodine that may have carried over in the steam. The licensee calculated that a total of about 1.7 curies (Ci) of radioactive gases may have been released, resulting in a dose at the site boundary of about 0.01 mrem to the whole body and 0.04 mrem to the thyroid. Most of this activity, approximately 1.5 curies, was attributed to the planned containment venting operation on February 17, 2000, that was necessary in order to open the containment for examination of the steam generators. This venting activity was performed in accordance with the licensee's procedures, and constituted a planned, controlled, and monitored radiological effluent release.

Radioactive liquids generated from this occurrence were drained into the liquid radioactive waste processing system to be treated, (i.e. filtered, demineralized, and sampled prior to release) in accordance with the licensee's Radiological Effluent Technical Specifications. On February 21, and 22, a small amount of liquid activity that had been introduced into the SG blowdown system piping during the event was unexpectedly released to the discharge canal during a planned discharge of the contents of a groundwater collection tank. The release was diluted in the discharge canal prior to release into the Hudson River. The total radioactive liquid released was estimated to be .0138 curies, resulting in an estimated whole body exposure to the public of 0.001 mrem.

All of the gaseous and liquid releases that are known, or assumed, to have occurred (based on the licensee's evaluation and assessment) from the #24 steam generator tube failure event, including the resultant exposure at the site boundary, are listed in Attachment 5.

4.4.2 Environmental Radiation Measurements

Evidence of significant noble gas releases may be detectable but are dependent on several factors including, the amount of radioactivity involved, the radiation and decay characteristics of the isotopes, the duration of the release, and meteorological conditions. Meteorological data during the first four hours of the event indicated that winds were light and variable (2-4 mph). A non-specific wind direction prompted the licensee to review all direct radiation measurement locations in the vicinity of Indian Point Station. To support the Radiological Environmental Monitoring Program, the licensee maintained several fixed radiation monitoring stations established in the environment surrounding the Indian Point plants. There are 32 thermoluminescent dosimeters (TLDs) surrounding the plant close to the site boundary and another 32 TLDs surrounding the plant at approximately 5 miles. There are about 20 additional TLDs at various other locations. In addition, there are 16 pressurized ion chambers (PICs) surrounding the plant at between 0.2 and 2 miles that are designed to provide continuous radiation readings at 15 minute intervals.

After the event, the environmental TLDs were changed and read with the following results:

	Range	Average
Inner ring TLDs	.0051-.010 mrem/hr	.0064 mrem/hr
Outer ring TLDs	.0051-.0083 mrem/hr	.0065 mrem/hr

Background comparison from 1998 Radiological Environmental Operating Report:

1998	Inner ring TLDs	.0056-.011 mrem/hr	.0066 mrem/hr
1998	Outer ring TLDs	.0060-.010 mrem/hr	.0068 mrem/hr

Based on the above comparison, the environmental TLDs read after the event did not show any radiation exposure distinguishable from naturally occurring background.

The licensee maintains a network of pressurized ion chamber (PIC) instruments (Reuter-Stokes) surrounding the facility. While not a regulatory requirement, these devices provided additional information relative to radiological dose impact. These electronic instruments are designed to continuously monitor and record the level of radiation in the vicinity. Ten out of the sixteen PICs responded with data during the event. All ten PICs indicated steady indication of background radiation throughout the duration of the steam generator tube failure event. However, one of the PIC units (sector 9) was noticed to perform erratically, well after any postulated or actual release. Review and evaluation of maintenance records associated with this particular unit revealed indications of deteriorating instrument performance as early as January 2000. While unexplained, the erratic performance could not be associated with any actual radiological cause. Accordingly, the sector 9 PIC data has been discounted as unreliable. All remaining PIC instruments provided supporting data that any release that occurred was not distinguishable from naturally occurring background.

Three soil samples were taken by the licensee between 0.25 and 2 miles North of Indian Point and 3 soil samples 1 mile South of the plant. The NRC and the State of New York also took 8 soil samples at various locations around the plant. No radioactivity except for naturally occurring radionuclides were detected in any of the soil samples. Air samples were obtained by the licensee from 9 continuously operating environmental air sampling stations that circle the plant between 0.4 - 6.4 miles. Analysis of these particulate and iodine air samples did not show any measurable radioactivity.

The Team conducted independent onsite and offsite surveys, collected independent offsite soil samples, and reviewed licensee data from offsite TLDs, offsite radiation monitors, and air and soil measurements. The team reviewed the licensee's radiological response to the event (Included as Attachment 4, Radiological Response Event Time Line) and determined that the licensee's radiological response and environmental monitoring of the event were adequate and met regulatory expectations and requirements. Based on the environmental monitoring data reviewed (including the results of radiation surveys conducted by licensee and Westchester County survey teams during the occurrence on February 15-16), the Team concluded that any radiological release that occurred was not measurable from naturally occurring background radiation; and confirmed that the licensee's radiological release and dose assessment was reasonable.

4.4.3 Indian Point Steam Generator Tube Failure Event Calculated Releases

A detailed summary of the calculated releases attributed to this event is contained in Attachment 5.

NRC Assessment

The Team reviewed the licensee's chemistry sample analyses, radiation monitoring data, and meteorological information that were pertinent to radiological release and public dose assessment associated with the steam generator tube failure event. Additionally, the Team performed independent radiological surveys on- and offsite, and collected soil samples offsite to confirm the absence of any trace or residual activity. The team reviewed the assumptions that were used by the licensee, and performed an independent computation to verify and validate the reasonableness of the licensee's dose assessment. This effort confirmed that the licensee's assumptions were conservative and that the dose assessment was an upper bound of the release due to this event.

Public Dose Assessment

In 40 CFR Part 190, the Environmental Protection Agency (EPA) established public dose limits resulting from the uranium fuel cycle as: 25 mrem per year to the whole body, 75 mrem per year to the thyroid, and 25 mrem to any other organ. In the Indian Point Unit 2 Radiological Effluent Technical Specifications, more stringent criteria are specified for gaseous and liquid effluents: 3 mrem to the whole body, and 10 mrem to any organ from radioactive liquid effluents in a year; and 10 mrem to the whole body, and 15 mrem to any organ from radioactive gaseous effluents in a year.

The exposure calculations resulting from the event were compared to the EPA and operating license limits as tabulated below.

	Whole Body	Thyroid	% of Tech Specs
Gaseous	0.0104 mrem	0.0425 mrem	0.104% WB; 0.28% Organ
Liquids	0.00092 mrem	0.0015 mrem	0.031% WB; 0.015% Organ
Total	0.0113 mrem	0.0440 mrem	
% of EPA	0.045 %	0.059 %	

Based on the above comparison, the conservatively calculated public exposures due to the event were a very small fraction of regulatory limits, and would be generally indistinguishable from naturally occurring background radiation. (Note: National Council on Radiation Protection and Measurements and the Environment Protection Agency report naturally occurring background to be between 300 and 400 millirem per year, depending on location.)

NRC Regulatory Guides[1] describe the computational method that NRC regards as an acceptable approach to estimate or project radiation dose to the public due to radiological releases to the atmosphere. The approach is dependent on several variables, including atmospheric conditions, radiological characteristics of the gases, applicable atmospheric dispersion and radiological dose factors, wind speed and direction, atmospheric stability; and release elevation, concentration, rate, and duration. Consequently, estimates of radioactivity released versus dose consequence are highly dependent on the data and assumptions used, and vary accordingly. Notwithstanding, independent analysis using a NRC computer code based on these Regulatory Guides (PC-DOSE), conservative assumptions, and actual radiological measurements confirmed that the total quantity of radioactive gases released as a result of the steam generator tube leak event did not result in any dose consequence distinguishable from naturally occurring background.

4.5 Steam Generator Maintenance and Inspection History

The Team reviewed the licensee's programs for inspecting and maintaining the steam generators, including a review of the results of the latest steam generator tube inspection and secondary chemistry performance. Although determination of the cause for the SG tube failure was outside the Team Charter, the information discussed below was collected to assist in review of the licensee's pre-event SG tube condition monitoring activities. All findings discussed below were forwarded to the NRC specialists responsible for reviewing the cause of the tube failure.

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[1]1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR 50, Appendix I, and 1.111, Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

The last steam generator inspection was completed in June 1997 during the scheduled Cycle 13 refueling outage. The scope of inspection included 100% inspection of all in-service tubes. The eddy current inspection was conducted using a combination Cecco-5 /bobbin probe. The baseline inspection was supplemented with a Plus Point rotating probe inspection at areas where the Cecco-5 probe could not access a specific tube location, including all of the row 2 and 3 tight radius U-bends.

The Team reviewed the qualification of the Cecco-5 probe and found it was qualified in accordance with industry standards. The inspector noted a minor discrepancy between the minimum required digitizing rate used for probe qualification and the allowed minimum digitizing rate during the 1997 inspections. The probe was qualified using a minimum digitizing rate of 33 samples per inch; however, the licensee's acquisition technique sheet used during the 1997 inspections allowed digitizing rates as low as 30 samples per inch. The digitizing rate is a measure of the number of data samples taken as the probe is pulled through the tube. The Team determined this was a documentation issue and that actual data was obtained above the minimum required digitizing rate.

As a result of the 1997 inspections and analysis, a total of 173 tubes were removed from service by plugging. Identified degradation mechanisms included outside diameter stress corrosion cracking (ODSCC) and primary water stress corrosion cracking (PWSCC) at dented tube support plate intersections, pitting and ODSCC in the tube sheet sludge pile region, and PWSCC in the tube sheet roll transition. In addition, one tube was plugged in the #24 SG for a PWSCC indication in a tight radius (row 2) U-bend. This was the first evidence of this degradation mechanism in the Indian Point 2 SGs. The licensee repaired 131 tubes with eddy current indications in the tube sheet roll transition. At the time of the event, 10.2% of the tubes in all four steam generators, or 1325 tubes, had been removed from service.

In-situ pressure tests were conducted on 6 tubes in the 1997 refueling outage. The licensee tested tubes containing eddy current indications assessed as having the most limiting structural characteristics. No leakage was identified. Based on the results of the in-situ pressure tests, and an assessment of the eddy current inspection results for the previous cycle of operation, the licensee completed an operational assessment that concluded that steam generator structural and leakage integrity was provided for the full cycle of operation.

In December 1998 the licensee requested a TS amendment for a one-time only extension of the SG inspection interval for the current operating cycle from June 13, 1999 to June 3, 2000. In a safety evaluation dated June 9, 1999, the NRC granted the licensee's request. The request was granted based on the 100% inspection conducted in June 1997 and the 304 days spent in cold shutdown during the operating cycle. The staff concluded that, based on the inspections conducted, the licensee's leakage monitoring and operational assessment, there was reasonable assurance that the SG tubes would maintain structural and leakage integrity for the extended period of operation.

Primary-to-secondary leakage was first identified by condenser off-gas sampling in September 1998. The leak rate was quantified at 0.5 gallons per day (gpd). The leak rate slowly increased during the next 12 months and reached 2 gpd when a plant trip resulted in the unit being shutdown to hot standby for 2 months starting in August 1999. During the shutdown the licensee performed tritium surveys that indicated that the #24 SG was the primary source of the leakage. Following startup in October 1999, the leakrate appeared to vary from 2 to 4 gpd but returned to the pre-shutdown levels of 1.5 to 2.0 gpd through December 1999. Starting in January 2000 the leak rate slowly increased to about 3-4 gpd just prior to the tube failure on February 15, 2000. The MS line radiation monitors first showed indication of leakage from the #24 SG on February 3, 2000. The team determined that this leak rate was significantly below the TS 3.1.F.2.a.1 limit of 432 gpd.

The failed tube was identified in the #24 SG as tube row 2 column 5, a tight radius U-bend tube. A visual inspection of the rupture area characterized the flaw as approximately 2 to 3 inches in length. Preliminary eddy current analysis characterized the flaw as PWSCC with an approximate length of 1.8 inches located at the apex of the U-bend. The licensee reviewed the Plus Point eddy current data taken at the flaw location during the 1997 refueling outage inspection and questioned the quality of the eddy current data collected at this location. Specifically, geometric variations in the tube circumference caused an uneven rotation of the eddy current probe as it was pulled through the tight radius U-bend tubes. The uneven probe rotation resulted in anomalous eddy current signals and reduced the probability of detection for indications in the tight radius U-bends. NRC specialists will perform an independent review of this data.

During the current forced outage the licensee initially planned a 100% inspection of all four steam generators, similar to the inspections conducted in the 1997 refueling outage. The inspection scope was subsequently expanded based on inspection results. The results of the current inspection will be reviewed by the NRC Office of Nuclear Reactor Regulation to determine any necessary SG corrective actions prior to the plant start-up.

The Team reviewed the licensee's methodology for determining the primary-to-secondary leakrate that resulted from the tube failure event. The leak rate was determined by comparing the charging pump flow, letdown flow, and pressurizer level response during the event. Additionally, a second leakrate calculation was performed based on the rate of change in steam generator water level during the event. The two methods yield comparable results. Both calculations are considered a "nominal" calculation, and do not account for potential sources of inaccuracy such as instrumentation error. The licensee's preliminary results concluded the leakrate at the initiation of the event was 146 gallons per minute (gpm), and was reduced to 0 gpm at the conclusion of the event. Operator action to rapidly lower primary system pressure, in accordance with the EOPs, was successful at decreasing the overall primary-to-secondary leakrate. The team evaluated that the licensee's methodology for calculating the primary-to-secondary leakrate was valid and provided reasonable results.

The Team reviewed the licensee's secondary chemistry performance during the last and previous cycles of operation. Measured chemistry parameters during the last cycle of operation followed industry recommended guidelines and practices. Although the licensee has complied with industry standards, the inspector noted some areas where the licensee did not take a proactive approach in managing secondary water chemistry performance: the plant was designed and built without a condensate polishing system to reduce impurities transported to the steam generators in the event of a main condenser tube leak, however, the main condensers were not completely upgraded to a leak tight design until 1995; the water treatment plant, used to provide secondary system make-up water, was not upgraded to a state-of-the-art system until December 1999; and the licensee initiated a secondary side copper reduction program in 1982, however, six low pressure feedwater heaters and the gland steam condenser still contain tubes manufactured of copper containing alloys.

There was one secondary chemistry upset during the last operating cycle. In October 1999, a tube leak in a feedwater sample cooler during a plant shutdown resulted in approximately 1500 gallons of river water being introduced into the steam generators during the reactor startup. The chemistry upset was cleaned up through extensive steam generator blowdowns prior to reactor startup. The Team determined that none of the secondary chemistry issues discussed above had a direct causal effect on the February 2000 SGTF (i.e., the failure was initiated from the primary not secondary side of the tube).

4.6 <u>Immediate and Interim Corrective Actions</u>

The Team determined that the licensee's immediate actions for this event were directed towards protecting the health and safety of the public. These actions included: the initial operator actions, the event declaration, and the staffing of the emergency response organization.

The Team concluded that station management initiated adequate interim corrective actions to review and address both the equipment and personnel performance issues identified during the event. Specifically, station management formed a team consisting of industry peers to review the implementation of the emergency plan, and also formed a Significance Level One (SL1) condition report Event Investigation Team (EIT) to review the event. Station management also mobilized the Command and Control Organization (CCO) to oversee the activities of these teams as well as to oversee safe plant operation during the recovery process. A station Recovery Plan was developed to focus the activities of the CCO.

The Team reviewed the SL1 EIT charter and the Recovery Plan. Both documents established a reasonable scope of activities, expectations, and assigned tasks. The CCO met twice per week and the SL1 EIT met daily. The Team observed a CCO meeting and determined that the status of issues pertinent to plant safety and recovery were reasonably communicated. The SL1 EIT was sufficiently staffed with 15 members and continued progress towards understanding the event was evident at the daily meetings. Recovery Plan implementation and the SL1 EIT review had not been completed by the end of the inspection. Therefore a full conclusion regarding the effectiveness of the licensee's planned corrective actions could not be reached. The NRC plans to review selected corrective actions prior to the plant restart.

5.0 CONCLUSIONS

The licensee took the necessary steps to mitigate this event, including shutdown of the reactor, identification and isolation of the faulted SG, cooldown of the RCS, declaration of the Alert, and staffing of the ERO. The Team noted that no radioactivity was measured off-site in excess of normal background levels and determined that the event did not impact the health and safety of the public. Necessary event mitigation systems worked properly.

The Team determined, however, that this event indicated significant performance problems in several broad areas that complicated the event response, delayed achieving a cold shutdown plant condition, and impacted the radiological release. Specific problem areas were discussed in Section 3.0, and included: equipment performance, operator performance, procedure quality, technical support, and performance of the ERO.

Several of equipment problems that challenged operators during this event, such as the degraded steam jet air ejector steam supply valve and an isolation valve seal water system design deficiency, were longstanding. In addition, some of the emergency plan implementation problems were similar to previously identified problems in this area; for example, the technical support center personnel did not consistently anticipate plant problems and make timely recommendations to the operators which was also a finding during the September 1999 emergency preparedness exercise. The Team concluded that the number and duration of the identified problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station. The Team recognized that, prior to the event, the licensee was in the process of implementing a station improvement program. This event demonstrated the need for continuous management attention to planned improvements to ensure they are timely and effective.