

= / R

From: Wayne Schmidt
To: Brian Holian, David Lew, Gregory Cranston, Richard Urban, Stephanie Coffin
Date: Fri, Jul 21, 2000 9:33 AM
Subject: SDP Panel package

Attached are the electron documents for the panel - I have and will fax the other attachments tot he summary.

N/B

(25)

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

Indian Point 2 Steam Generator Special Inspection Summary

Prepared by: Wayne Schmidt - Team Leader - Region I - 610-337-5315

Attachments:

1. NRC Preliminary CDF/LERF assessment
2. Con Edison - Calculation of CDF and assessment of no LERF - pages 1-3 of 26
3. Con Edison disagreement with several technical issues - 5 pages, July 20, 2000 - 11am
4. Con Edison overall disagreement with team findings, presented by VP - Engineering at the end of the exit meeting July 20, 2000 - 2 pm.
5. NRR Comments on Attachment 2 - E-mail

VI. Inspection Scope:

The NRC conducted a special team inspection to review the causes of the failure of a steam generator tube on February 15, 2000. The NRC team members included personnel from the Office of Nuclear Reactor Regulation and Region I, and NRC-contracted specialists in steam generator eddy current testing. The purposes of the special inspection were to determine the adequacy of Con Edison's performance during the 1997 steam generator inspections and to assess Con Edison's root cause evaluation, date April 14, 2000. The team also reviewed portions of the June 2, 2000, Con Edison steam generator condition monitoring and operational assessment report (CMOA) for possible regulatory issues.

VII. Conclusion/Root Cause:

Con Edison returned Indian Point, Unit 2, to service in 1997 in a condition that deteriorated with time to the point that a steam generator tube failure occurred within approximately 23 months of operation

A failure to identify significant performance issues during the 1997 steam generator inspection resulted from Con Edison's weak technical management and oversight of the steam generator inspection program. Of most significance, Con Edison failed to identify: inside diameter (ID) primary water stress corrosion cracking (PWSCC) in six small radius U-bend SG tubes, including tube R2C5 in SG 24, which failed in February 2000. Con Edison failed to identify several factors that caused significant limitations and uncertainties in data collection and analyses, this increased the likelihood that steam generator tubes with detectable flaws would have been left in service. Specifically, Con Edison did not evaluate and take necessary actions to compensate for equipment and technique challenges to flaw detection or to consolidate steam generator condition information to assess the significance of the new ID PWSCC degradation mechanism. Overall, Con Edison did not ensure an adequate, integrated technical understanding of the steam generator conditions.

~~**PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY**~~

VIII. Performance Issues;

1. Based on an independent NRC review of the eight U-bend PWSCC indications detected during the 2000 inspection, the NRC determined that six should have been identified in 1997. This included SG 24, R2C5, the tube that leaked on February 15, 2000. During the 1997 steam generator inspection Con Edison did not adequately respond to issues that decreased the probability of detection of small radius U-bend tube indications and increased the likelihood of apex flaws in the small radius U-bend steam generator tubes.
 1. Con Edison did not adequately evaluate poor quality data (low signal to noise ratios) that was encountered during the eddy current inspections in 1997. Con Edison failed to evaluate the effect on the probability of detection of small radius U-bend tube indications.
 2. Con Edison did not adequately respond to a PWSCC indication in the U-bend area of tube R2C67 in SG 24, which was identified during the 1997 outage. This indication, which was located in the apex of this small diameter tube, was a new and significant degradation mechanism at Indian Point 2. Apex cracking is more likely to burst than other u-bend cracks. After identifying an apex U-bend PWSCC flaw in SG 24 tube R2C67, Con Edison took no actions to determine the root cause and took on actions to ensure that this new mechanism understood.
 3. Con Edison did not sufficiently assess eddy current probe restrictions in the upper support plate encountered during the 1997 steam generator inspections, with respect to the potential for flow slot hourglassing. Con Edison did not evaluate the potential for increased apex stresses and PWSCC.
2. Con Edison did not properly set-up the U-bend plus-point eddy current probe in 1997, which negatively affected the probability of detection of U-bend indications. The probe was not set-up with the required calibration standard or with the phase rotation required by the EPRI qualified technique sheet.
3. Con Edison did not have an accurate method of measuring nor some criteria for determining when significant hourglassing of the upper tube support plates had taken place. As such Con Edison could not conduct and submit an evaluation of how the hourglassing affected the long term integrity of the small radius U-bends tubes beyond row 1.
4. The team also concluded that Con Edison's root cause analysis for the event, dated June 14, 2000, did not adequately address their failure to identify deficiencies and limitations related to the 1997 inspection of the low radius U-bend regions. While the root cause analysis attributed the tube failure to a flaw that was obscured by eddy

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

current signal noise, it did not identify nor address inadequacies in the management of the 1997 steam generator inspection.

IV Risk and Significance Assessment:

NRC Assessment:

During the February 15, 2000, event the leakage from the apex crack in SG 24 tube R2C5 did not reach the full steam generator tube rupture (SGTR) flowrate, due to remaining crack ligaments in the flaw area. However, if additional stress had been placed on the flaw by any larger than normal differential pressure the SGTR leakrate could have been reached. Therefore the risk analysis was done assuming an SGTR. The risk associated with the condition of the tubes during Cycle 14 comes from several potential accident sequences:

1. Spontaneous rupture of a tube, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.
2. Rupture of one or more tubes induced by a steam system depressurization event, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.
3. Rupture of one or more tubes induced by a reactor system over-pressurization event, causing core damage and bypass of the containment by large radioactive releases.
4. A core damage event that occurs with the reactor system at normal operating pressure, inducing tube rupture by increasing tube temperature and/or tube differential pressure, causing bypass of the containment by large radioactive releases.

Of these, the first two increase both the core damage frequency (CDF) and the frequency of large radioactive releases bypassing the containment and reaching the environment (hereafter assumed to be a "large early release"). The latter two sequences are already included in the plant's core damage frequency estimate, but would not normally be included in its large early release frequency (LERF). The induced tube ruptures cause them to make contributions to LERF.

The NRC staff estimated the sum of these tube degradation related risk contributions to get a yearly incremental CDF/LERF for an SGTR of approximately 1×10^{-4} /reactor year (RY). Using the single SGTR over a 23 month period established a low bound event frequency of approximately 0.5 SGTR/RY. Because the condition deteriorated with time, it can be argued that the initiating event frequency had not increased over the first year but only during the last year of operation. This would establish a high bound of 1 SGTR/RY. Multiplying these two estimates of the initiating event frequency by the SGTR CDF/LERF probability results in estimates for the incremental CDF of between 5×10^{-5} /RY and 1×10^{-4} /RY.

~~**PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY**~~

Con Edison Assessment:

The preliminary Con Edison assessment states that the probability of CDF resulting from a SGTR is $1 \times 10^{-6}/\text{RY}$ the initially assumed frequency of a SGTR as $1.3 \times 10^{-2}/\text{RY}$, so the yearly incremental CDF conditional core damage probability is $.77 \times 10^{-4}/\text{RY}$ ($1 \times 10^{-6}/1.3 \times 10^{-2}$)

Con Edison completed a more detailed calculation of CDF for the actual conditions present at the time of the tube failure and for the actual leakrate observed. This calculation assumes that the flow rate from the leak remains at below the design basis rate, which reduces the time to core damage and postpones the release time to the point that Con Edison believes it would not be considered an early release.

Significance Determination Process:

The magnitudes of the yearly incremental CDF for an SGTR in the initial NRC ($1 \times 10^{-4}/\text{RY}$) and the preliminary Con Edison estimate ($.77 \times 10^{-4}/\text{RY}$) are relatively the same.

The new Con Edison calculation indicates a specific conditional CDF of $2.2 \text{ E-}6$, with no LERF

The current guidance for assigning risk significance is contained in a draft NUREG/CR titled "Basis Document for Large Early Release Frequency (LERF) Significance Determination Process (SDP) - Inspection Findings That May Affect LERF." The Office of Research is sponsoring the project at Brookhaven National Laboratory that is developing this guidance. The guidance is summarized in Table 1 of that document as shown here.

incremental CDF Range/ry	SDP Based on CDF	SDP Based on LERF
$\geq 10^{-4}$	Red	Red
$< 10^{-4} - 10^{-5}$	Yellow	Red
$< 10^{-5} - 10^{-6}$	White	Yellow
$< 10^{-6} - 10^{-7}$	Green	White
$< 10^{-7}$	Green	Green

Therefore, the CDF/LERF increment associated for a SGTR event is considered to be clearly above the $10^{-5}/\text{RY}$ criterion for a "red" significance determination. However the Con Edison assumption for lower than design SGTR leakage drops the CDF to $2.2 \text{ e-}6$ with no LERF - so this would be a white CDF finding with no LERF.

V. Potential Notices of Violations

10 CFR 50, Appendix B Criterion IX - Control of Special Processes and Criterion XVI -

~~**PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY**~~

Corrective Actions, require, in part, that Con Edison, conduct an steam generator eddy current inspection program that promptly identifies and takes corrective actions for significant conditions adverse to quality.

Contrary to the above, Con Edison in 1997 failed to conduct a steam generator eddy current inspection program that promptly identified and took corrective actions for significant conditions adverse to quality. Consequently, a steam generator tube with detectable degradation was left in service following the 1997 refueling outage, eventually leading to the February 15, 2000, steam generator 24 tube row 2 column 5 failure. Specifically, Con Edison did not:

1. adjust the program to compensate for high noise signals in the low radius U-bend areas; these high noise signals negatively affected flaw detection capability;
2. take adequate corrective actions following identification of a new tube degradation mechanism, i.e., inside diameter (ID) primary water stress corrosion cracking (PWSCC) at the apex of a low radius U-bend tube;
3. establish a mechanism to monitor for and have an acceptance criteria for significant upper support plate flow slot hourglassing. Further, the potential existence and impact of upper support plate hourglassing on PWSCC flaws in the apex region of a low row U-bend tube was not assessed following the identification in 1997 of eddy current probe restrictions; and
4. ensure the use of properly qualified eddy current techniques. The U-bend plus-point eddy current probe, was not set-up with the proper calibration standard or with the phase rotation specified by the EPRI qualified technique sheet, which affected the probability of detection of U-bend indications.

~~**PREDECISIONAL INSPECTION INFORMATION**~~
~~**INTERNAL NRC STAFF USE ONLY**~~

May 4, 2000

MEMORANDUM TO: A. Randolph Blough, Director
Division of Reactor Projects
Region I

FROM: Richard J. Barrett, Chief */RA/*
Probabilistic Risk Assessment Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

SUBJECT: RISK ASSESSMENT AND INPUT TO SIGNIFICANCE
DETERMINATION PROCESS FOR CONDITION OF INDIAN POINT,
UNIT 2, STEAM GENERATOR TUBES DURING OPERATIONAL
CYCLE 14 (TAC NO. MA8219)

As you requested, the Probabilistic Safety Assessment Branch has reviewed the information available and performed a risk assessment for the recent findings at Indian Point, Unit 2.

During operation Cycle 14, Indian Point, Unit 2, experienced degradation of steam generator tubes that culminated in failure of a flaw in the U-bend of tube R2C5 in steam generator 24. In addition, inspection following the tube failure event revealed five additional tubes with defects in the same region of steam generator 24, plus other defects in other regions and other generators. However, none of these other defects appears to have become susceptible to induced rupture by the time tube R2C5 ruptured spontaneously.

The risk associated with the condition of the tubes during Cycle 14 comes from several potential accident sequences:

1. Spontaneous rupture of a tube, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.
2. Rupture of one or more tubes induced by a steam system depressurization event, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.
3. Rupture of one or more tubes induced by a reactor system over-pressurization event, causing core damage and bypass of the containment by large radioactive releases.

CONTACT: Steve Long, SPSB/DSSA
415-1077

Attachment 1

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

A. Randolph Blough

- 2 -

4. A core damage event that occurs with the reactor system at normal operating pressure, inducing tube rupture by increasing tube temperature and/or tube differential pressure, causing bypass of the containment by large radioactive releases.

Of these, the first two increase both the core damage frequency (CDF) and the frequency of large radioactive releases bypassing the containment and reaching the environment (hereafter assumed to be a "large early release"). The latter two sequences are already included in the plant's core damage frequency estimate, but would not normally be included in its large early release frequency (LERF). The induced tube ruptures cause them to make contributions to LERF.

The sum of these tube degradation related risk contributions for Indian Point Unit 2 during Cycle 14 is estimated to be a probability of core damage accident with a large release at approximately 10^{-4} . This risk occurred mostly during the latter year of the operational cycle. The basis for this estimate is discussed below for each potential accident sequence, individually.

Spontaneous Tube Rupture:

The Indian Point, Unit 2, probabilistic risk assessment (PRA) includes this sequence. The probability of the initiating event, spontaneous tube rupture, was assumed to be 1.3×10^{-2} per reactor-year of operation (RY) and the resulting CDF was estimated as 1.0×10^{-6} /RY. From this, the conditional probability for failing to mitigate a rupture after it occurs is inferred to be 7.7×10^{-5} . This number is comparable to the conditional probability values obtained from the NUREG-1150 model for Surry, 1.4×10^{-4} , and from the NRC's Rev. 2 QA SPAR model for Indian Point, Unit 2, 3.3×10^{-4} . So, given that the spontaneous rupture initiating event did occur at Indian Point, Unit 2, the conditional probability of core damage is estimated to be about 1×10^{-4} . Because most of the core damage sequences resulting from spontaneous tube rupture involve loss of steam system integrity, approximately the same conditional probability applies to the occurrence of a large early release of radioactive material to the environment.

The most probable reasons for a spontaneous rupture event to cause core damage involve human errors while attempting to cool down the unit. The probability of the operators making (and not correcting) these errors depends on the amount of time available to them, which depends on the leak rate through the ruptured tube. The PRAs assume that the rupture is as large as can occur with one tube, which creates a leak flow of several hundred gallons per minute (gpm). The rupture that actually occurred at Indian Point, Unit 2, resulted in only about 150 gpm of leakage. So, the operators had much more time to correct the situation than is assumed in the PRA models that were used above to estimate the conditional probability of core damage. Thus, it can be argued that the probability of the Indian Point operators failing to mitigate this particular rupture was much lower than 10^{-4} . However, the flaw that failed in the Indian Point tube was about 2 inches long, and a flaw this long is capable of bursting to the extent assumed in the PRAs. The fact that the tube flaw was held partially closed by several ligaments across the flaw is the reason that it did not open completely and leak much more. Experience has shown that the probability is about 0.5 that tubes with large flaws will leak substantially or only partially break open before they fail completely, allowing operators an

Attachment 1

~~PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY~~

A. Randolph Blough

- 3 -

opportunity to intercede before complete failure occurs. Thus, the fact that the type of degradation that occurred can result in large flaws and that the flaw that failed was indeed large indicates that the risk associated with the degradation at Indian Point, Unit 2, is best estimated as having about 10^{-4} conditional probability of core damage and large release from the spontaneous rupture sequence.

Ruptures Induced by Steam System Depressurization:

Core damage sequences of this type are not generally included in licensees' PRAs, but have been evaluated by the NRC in NUREGs-0844, -1477 and -1570. They are similar to the spontaneous rupture sequences in licensees' PRAs except that the loss of steam system integrity comes first and causes the tube rupture instead of *vice versa*. As in the spontaneous rupture sequences, the most probable path to core damage involves errors in the operators' response to the conditions that occur. For a tube rupture induced by a steam system depressurization, the errors are estimated to be more probable because the events are more complicated and the operators do not normally drill on this type of sequence.

In the case of Indian Point, Unit 2, it is clear that a secondary depressurization event would have caused tube R2C5 to rupture when it was in the weakened condition that just preceded its spontaneous rupture. During that period, the CDF (and large release frequency) is estimated using a steam system depressurization frequency of $7.6 \times 10^{-3}/\text{RY}$, the assumption that only one of four steam generators was susceptible, a conditional rupture probability of 1.0, and a human error probability of 10^{-2} . The result is an increase in both the CDF and the large release frequency of about $1.9 \times 10^{-5}/\text{RY}$.

However, in order to estimate the increase in probability of core damage and large release, it is necessary to consider the length of time that this increase in frequency is applicable. Based on the currently available information, the period of time the tube was susceptible to this accident sequence is estimated in Appendix A as approximately 4 to 11 months or 0.3 to 0.9 year. Thus, the number of ruptures that would be mathematically "expected" for this frequency over this period is 6×10^{-6} to 1.7×10^{-5} . For such small expectation values, the probability of occurrence of a single event is numerically indistinguishable, so the increase in the probability of core damage and large release from this sequence for this condition is estimated to be about 1×10^{-5} .

Ruptures Induced by Reactor System Over-Pressurization Events:

Tube ruptures that are induced by the normal operational occurrences that involve slight elevations in reactor system pressure are considered to be captured by the value used for the frequency of spontaneous ruptures. The additional sequences considered here are those involving gross over-pressure events that, by themselves, would produce core damage. These result from failure of the reactor control system to shut down the nuclear chain reaction when required by a design-basis transient, such as loss of feed water to the steam generators. These events are called anticipated transients without scram (ATWS) events. Most licensees' PRAs include core damage sequences due to ATWS events, but do not consider the probability that such an event could also rupture a steam generator tube, causing containment bypass by the radioactive material it would release from the damaged reactor core.

Attachment 1

~~PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY~~

A. Randolph Blough

- 4 -

The PRA for Indian Point, Unit 2, estimates a CDF contribution of $1.81 \times 10^{-6}/\text{RY}$ due to ATWS events. ATWS events that create a reactor coolant system pressure above 3,200 psi are assumed to lead to core damage. During the period of extreme reactor system pressure, the steam system pressure is expected to be at the steam system safety valve setpoint, producing a pressure differential across the steam generator tube walls of at least 2,100 psid. Based on the rate of degradation estimated in Appendix A, we estimate that an ATWS event would have induced tube R2C5 to rupture for a period greater than 3 months. In the same manner described above for steam system depressurization sequences, this results in an estimated increase in the large early release probability that is $> 4 \times 10^{-7}$, perhaps by a factor > 3 . There is no increase in the core damage probability because the ATWS sequences that would induce the tube rupture are already part of the CDF estimate, and the addition of the tube rupture potential is not assumed to change the frequency with which ATWS would cause core damage.

Tube Ruptures Induced by Other Core Damage Sequences:

Other core damage sequences that are included in licensees' and NRC's PRAs may also cause large releases by inducing steam generator tube ruptures, but this effect is rarely included in the results of current PRAs. The studies documented in NUREG-1150 and particularly NUREG-1570 do address this potential for large releases to bypass containment due to tube failures. For accident sequences in which the reactor coolant system (RCS) remains at high pressure, the failures of flawed tubes may be caused by steam system depressurization that sometimes occurs as an essential or incidental part of the event sequence that leads to core damage. Also, for sequences with high-RCS pressure and dry steam generators (hi/dry sequences), tube failure may be induced when the overheating reactor core causes the tube temperatures to rise so high that their metal weakens. Tubes with flaws that would not fail upon steam system depressurization may still fail when the tube temperatures increase, later in the accident sequence. This is clearly the case for the Indian Point tube for some period during the last cycle, before it was susceptible to failure by steam system depressurization, alone. It also is clear that, for some shorter period of time, tube R2C5 would have failed if dry and overheated by a high-pressure core damage accident, even if the steam system remained pressurized.

To accurately estimate the additional probability of a large release due to a core damage accident during the last cycle, it is necessary to separately identify the hi/dry core damage sequence frequency and subdivide it into cases with and without steam system depressurization. It also is necessary to estimate the time periods during which tube R2C5 was susceptible to rupture 1) from steam system depressurization, alone, 2) from high temperature without steam system depressurization, and 3) from the combination of high temperatures and steam system depressurization.

However, without expending the effort to perform this detailed analysis, it can be seen that the result would not substantially change the overall risk estimate for the situation at Indian Point Unit 2, during Cycle 14. This is based on the fact that the total CDF is estimated to be $2.6 \times 10^{-5}/\text{RY}$. Although the majority of this frequency is expected to be hi/dry sequences, and about half of those sequences may involve steam system depressurization, the contribution to the total increase in the large release probability would still be about an order of magnitude less than the dominant contribution from spontaneous tube rupture, even if tube R2C5 was susceptible for about a year.

Attachment 1

~~PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY~~

A. Randolph Blough

- 5 -

Summarization of Overall Risk Increase:

On the basis of the foregoing discussions, it is estimated that the risk increase caused by the degradation of the tubes at Indian Point, Unit 2, during operational Cycle 14 is approximately 10^{-4} increase in core damage probability and a similar magnitude increase in large release probability. The risk from spontaneous rupture is the dominant contributor to the increases in both the core damage and the large release probabilities. The risk contribution from ruptures induced by steam system depressurizations adds about 10 percent of these totals, and the risk contribution from other core damage sequences that induce tube failure adds perhaps another 10 percent to the probability of large release, without increasing the core damage probability. More detailed analysis is not expected to change the magnitude of this estimate.

The risk input for use in a Significance Determination in accordance with the new Reactor Oversight Process is provided in Appendix B.

If you or your staff would like to discuss this assessment in further detail, please feel free to contact me or Steve Long.

cc: William M. Dean

~~PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY~~

Appendix A

Flawed Tube Strength as A Function of Time

Based on the license's reanalysis of their eddy current results from 1997, it appears that an inside diameter flaw approximately 2.4 inches long and averaging approximately 72 percent through wall was present in steam generator 24 tube R2C5 when the plant was returned to service.

Based on these flaw size measurements, NRC staff in the Division of Engineering performed burst pressure estimates for the subject tube at the time it was returned to service. Available burst pressure prediction models apply specifically to straight tubes rather than to u-bend geometries. These straight tube models indicate a burst pressure in the range of 3200 to 3620 psi. Westinghouse work in the early 1980's indicates that tubes exhibit higher burst strengths in the u-bends for a given size flaw than in the straight length portions due to the cold-worked state of the material in the u-bends. This Westinghouse work is not well documented nor is there much corroborating evidence for this work. The best that can be drawn from this information at this time is that burst pressures are somewhere between zero and 58 percent higher in the u-bend than the straight length regions for given size flaws. Thus, the staff concludes that the subject tube had a burst capability in the range of 3200 to 5700 psi at the time the plant was returned to service in 1997.

When the tube burst during operation, it's burst pressure had decreased to the plant's normal operating pressure differential, 1600 psid. The period of power operation that elapsed between these times was 22.5 months.

Assuming that the growth in the flaw created a decrease in strength that was linear with time, the following table was constructed for the duration of the periods that the flawed tube was susceptible to rupture at various pressure levels that are important thresholds for the risk assessment process.

Initial strength	= 3,200 - 5,700 psid	at	23 months
TI-SGTR threshold	< 2,800 psid*	for	7 - 17 months
PI-SGTR threshold	< 2,350 psid	for	4 - 11 months
Spontaneous rupture	= 1,600 psid		(instantaneous)

* This value is an approximation, based on the stress magnification factor that resulted in a 50 percent failure probability in the analysis previously performed for the Farley, Unit 1, license amendment application review. Of the analyses currently available to the staff, that one is the most similar to the Indian Point, Unit 2, reactor. However, that analysis contained many assumptions about the location of the flaw and the spatial distribution of tube temperatures that are not identical to the situation at Indian Point, Unit 2. In addition, these two reactors have not been verified to produce the same thermal-hydraulic conditions for severe accident sequences. However, because the value is not crucial to the conclusion, it is considered sufficient and useful to indicate the nature of the situation.

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

Appendix B

Significance Determination Input

The draft significance determination process (SDP) for the New Reactor Oversight Process is based on changes to core damage frequency associated with a condition at a power reactor unit. For conditions that increase the frequency of a large early release (LERF) the threshold significance determination criteria are reduced by a factor of 10, compared to the criteria used for core damage sequences that do not produce a large, early release. The guidance for core damage sequences involving steam generator tube rupture is to consider them as LERF sequences .

The current guidance for assigning risk significance is contained in a draft NUREG/CR titled "Basis Document for Large Early Release Frequency (LERF) Significance Determination Process (SDP) - Inspection Findings That May Affect LERF." The Office of Research is sponsoring the project at Brookhaven National Laboratory that is developing this guidance. The guidance is summarized in Table 1 of that document as shown here.

Table 1 Risk Significance Based on LERF and CDF		
Frequency Range/ry	SDP Based on CDF	SDP Based on LERF
$\geq 10^{-4}$	Red	Red
$< 10^{-4} - 10^{-5}$	Yellow	Red
$< 10^{-5} - 10^{-6}$	White	Yellow
$< 10^{-6} - 10^{-7}$	Green	White
$< 10^{-7}$	Green	Green

The conceptual question is how to assign a frequency to an accident initiating event that has happened once as the consequence of a condition that has developed over a period of time. The following discussion is considered sufficiently quantitative to establish the risk input for determining the "color" of the situation that occurred at Indian Point, Unit 2.

Indian Point, Unit 2, was returned to service in 1997 in a condition that deteriorated with time to the point that a steam generator tube rupture occurred within approximately 23 months of operation. The risk assessment indicates that the reactor was susceptible to the various accident sequences primarily during the last year of this period. If the licensee's tube inspection and operational assessment processes that led to this event were repeated without improvement, it is expected that a similar result would occur. This is used to establish an average frequency for the steam generator tube rupture initiating event of about 0.5/RY. Because the condition deteriorated with time, it can also be argued the initiating event frequency had zero increase over the first year and was increased about 1.0/RY during the second year. Multiplying these two estimates of the initiating event frequency by the probability that core damage would not be averted (about 1×10^{-4}) results in estimates for the incremental CDF of 5×10^{-5} /RY and 1×10^{-4} /RY, respectively. Consideration of the other pertinent sequences

Attachment 1

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

Appendix B

- 2 -

(where tube rupture is induced instead of initiating the sequence) is expected to add an additional increase on the order of $10^{-5}/RY$. Therefore, the CDF/LERF increment associated with this event is considered to be clearly above the $10^{-5}/RY$ criterion for a "red" significance determination.

It should be noted that, if this risk analysis had been formally utilized as part of the revised reactor oversight program, it would have been subjected to additional review and discussion with the licensee and with the SDP and Enforcement Review Panel during the process for finalizing a significance determination. In addition, the assignment of a color in the significance determination process would depend upon a determination that the action or inaction that created the risk increment constituted inadequate performance by the licensee. Because, the agency has decided not to apply the revised program to this event at Indian Point, these steps were not taken. Therefore, this analysis should not be construed as the NRC's significance determination or the final establishment of a "color" for this event.

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

From: Steven Long
To: Richard Barrett, Thomas Shedlosky
Date: Thu, Jul 20, 2000 11:22 AM
Subject: Re: ConEd Risk Analysis of IP-2 SGTR

Tom,

I read the licensee's risk assessment and have some observations:

1. I basically agree with their results for what they did, but note that it is a calculation of the conditional core damage probability (CCDP) for an SGTR event with low break flow rate, not an assessment of the level of risk increase (deltaCDF and deltaLERF) that the plant had due to the degraded condition of the tubes. There are two important differences discussed below.
2. The licensee had no way of knowing before the tube failure that it would have such a low flow rate. The average SGTR has had about 350 gpm and the maximum has been around 700 gpm. So, part of the difference between their CCDP for the event that they actually experienced and the deltaLERF that the NRC uses for our significance determination process (SDP) is their luck in having the degradation revealed by a small failure instead of a large one. From our review of the size of the flaw that failed, it is obvious that much larger flow rates could have occurred if that long flaw had not been held mostly closed by multiple remaining ligaments. There is no guarantee that such ligaments will always be present in flaws or even that those that were present in this flaw would hold for the 52 hour duration assumed to be available in the licensee's human error probability calculations. (Some of the human errors involve leaving the flaw under stress for extended periods.)
3. There are other types of accidents, besides spontaneous tube rupture, that contribute to deltaLERF. These are steam-side depressurization events and core damage events that would have induced the tube to rupture if they had occurred before the spontaneous rupture occurred. These types of events are included in the PRAs (and some in the design basis), but without the potential for complication by induced SGTR. My risk assessment input to our SDP does consider these other types of accident sequences in addition to the spontaneous rupture sequence. They come in at the low E-5/RY range, so they don't dominate my result. However, they would have to be considered in detail before one could conclude that the deltaLERF for the IP2 SG condition was less than 1E-5, and therefore not "red".

So, in summary, I don't dispute IP2's CCDP analysis, but I do not agree that it is the proper basis for assessing the risk of the situation that was created by your finding that their inspection of their tubes was inadequate to justify the run time that they attempted.

Steve Long

>>> Thomas Shedlosky 07/20 8:55 AM >>>

Attachment 5

~~PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY~~

I've attached a copy of the ConEd risk assessment of the February 15th SGTR, please note that ConEd has evaluated the condition at the actual maximum primary to secondary flow rate of 109 g.p.m. This allowed them to update the HRAs and also to take credit for charging.

The issue will be moving into enforcement space shortly because the inspection that reviewed the steam generator tube inspection program concludes today with its exit meeting. We'll continue to need your support.

Tom Shedlosky
610-337-5171

Attached: MSWord Document psa-000717-1rev0.doc

CC: Brian Holian, Wayne Lanning

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

Indian Point 2 Steam Generator Special Inspection Summary

Prepared by: Wayne Schmidt - Team Leader - Region I - 610-337-5315

Attachments:

- 1 - NRC Preliminary CDF/LERF assessment
2. - Con Edison - Calculation of CDF and assessment of no LERF.

I. Inspection Scope:

The NRC conducted a special team inspection to review the causes of the failure of a steam generator tube on February 15, 2000. The NRC team members included personnel from the Office of Nuclear Reactor Regulation and Region I, and NRC-contracted specialists in steam generator eddy current testing. The purposes of the special inspection were to determine the adequacy of Con Edison's performance during the 1997 steam generator inspections and to assess Con Edison's root cause evaluation, date April 14, 2000. The team also reviewed portions of the June 2, 2000, Con Edison steam generator condition monitoring and operational assessment report (CMOA) for possible regulatory issues.

II. Conclusion/Root Cause:

Con Edison returned Indian Point, Unit 2, to service in 1997 in a condition that deteriorated with time to the point that a steam generator tube failure occurred within approximately 23 months of operation

A failure to identify significant performance issues during the 1997 steam generator inspection resulted from Con Edison's weak technical management and oversight of the steam generator inspection program. Of most significance, Con Edison failed to identify: inside diameter (ID) primary water stress corrosion cracking (PWSCC) in six small radius U-bend SG tubes, including tube R2C5 in SG 24, which failed in February 2000. Con Edison failed to identify several factors that caused significant limitations and uncertainties in data collection and analyses, this increased the likelihood that steam generator tubes with detectable flaws would have been left in service. Specifically, Con Edison did not evaluate and take necessary actions to compensate for equipment and technique challenges to flaw detection or to consolidate steam generator condition information to assess the significance of the new ID PWSCC degradation mechanism. Overall, Con Edison did not ensure an adequate, integrated technical understanding of the steam generator conditions.

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

III. Performance Issues;

1. Based on an independent NRC review of the eight U-bend PWSCC indications detected during the 2000 inspection, the NRC determined that six should have been identified in 1997. This included SG 24, R2C5, the tube that leaked on February 15, 2000. During the 1997 steam generator inspection Con Edison did not adequately respond to issues that decreased the probability of detection of small radius U-bend tube indications and increased the likelihood of apex flaws in the small radius U-bend steam generator tubes.
 1. Con Edison did not adequately evaluate poor quality data (low signal to noise ratios) that was encountered during the eddy current inspections in 1997. Con Edison failed to evaluate the effect on the probability of detection of small radius U-bend tube indications.
 2. Con Edison did not adequately responded to a PWSCC indication in the U-bend area of tube R2C67 in SG 24, which was identified during the 1997 outage. This indication, which was located in the apex of this small diameter tube, was a new and significant degradation mechanism at Indian Point 2. Apex cracking is more likely to burst than other u-bend cracks. After identifying an apex U-bend PWSCC flaw in SG 24 tube R2C67, Con Edison took no actions to determine the root cause and took on actions to ensure that this new mechanism understood.
 3. Con Edison did not sufficiently assess eddy current probe restrictions in the upper support plate encountered during the 1997 steam generator inspections, with respect to the potential for flow slot hourglassing. Con Edison did not evaluate the potential for increased apex stresses and PWSCC.
2. Con Edison did not properly set-up the U-bend plus-point eddy current probe in 1997, which negatively affected the probability of detection of U-bend indications. The probe was not set-up with the required calibration standard or with the phase rotation required by the EPRI qualified technique sheet.
3. Con Edison did not have an accurate method of measuring nor some criteria for determining when significant hourglassing of the upper tube support plates had taken place. As such Con Edison could not conduct and submit an evaluation of how the hourglassing affected the long term integrity of the small radius U-bends tubes beyond row 1.
4. The team also concluded that Con Edison's root cause analysis for the event, dated June 14, 2000, did not adequately address their failure to identify deficiencies and limitations related to the 1997 inspection of the low radius U-bend regions. While the root cause analysis attributed the tube failure to a flaw that was obscured by eddy

~~PREDECISIONAL INSPECTION INFORMATION~~
~~INTERNAL NRC STAFF USE ONLY~~

current signal noise, it did not identify nor address inadequacies in the management of the 1997 steam generator inspection.

IV Risk and Significance Assessment:

NRC Assessment:

During the February 15, 2000, event the leakage from the apex crack in SG 24 tube R2C5 did not reach the full steam generator tube rupture (SGTR) flowrate, due to remaining crack ligaments in the flaw area. However, if additional stress had been placed on the flaw by any larger than normal differential pressure the SGTR leakrate could have been reached. Therefore the risk analysis was done assuming an SGTR. The risk associated with the condition of the tubes during Cycle 14 comes from several potential accident sequences:

1. Spontaneous rupture of a tube, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.
2. Rupture of one or more tubes induced by a steam system depressurization event, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.
3. Rupture of one or more tubes induced by a reactor system over-pressurization event, causing core damage and bypass of the containment by large radioactive releases.
4. A core damage event that occurs with the reactor system at normal operating pressure, inducing tube rupture by increasing tube temperature and/or tube differential pressure, causing bypass of the containment by large radioactive releases.

Of these, the first two increase both the core damage frequency (CDF) and the frequency of large radioactive releases bypassing the containment and reaching the environment (hereafter assumed to be a "large early release"). The latter two sequences are already included in the plant's core damage frequency estimate, but would not normally be included in its large early release frequency (LERF). The induced tube ruptures cause them to make contributions to LERF.

The NRC staff estimated the sum of these tube degradation related risk contributions to get a yearly incremental CDF/LERF for an SGTR of approximately 1×10^{-4} /reactor year (RY). Using the single SGTR over a 23 month period established a low bound event frequency of approximately 0.5 SGTR/R.Y. . Because the condition deteriorated with time, it can be argued that the initiating event frequency had not increased over the first year but only during the last year of operation. This would establish a high bound of 1 SGTR/R.Y. . Multiplying these two estimates of the initiating event frequency by the SGTR CDF/LERF probability results in estimates for the incremental CDF of between 5×10^{-5} /RY and 1×10^{-4} /RY.

~~**PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY**~~

Con Edison Assessment:

The preliminary Con Edison assessment states that the probability of CDF resulting from a SGTR is $1 \times 10^{-6}/RY$ the initially assumed frequency of a SGTR as $1.3 \times 10^{-2}/RY$, so the yearly incremental CDF conditional core damage probability is $.77 \times 10^{-4}/RY$ ($1 \times 10^{-6}/1.3 \times 10^{-2}$)

Con Edison completed a more detailed calculation of CDF for the actual conditions present at the time of the tube failure and for the actual leak rate observed. This calculation assumes that the flow rate from the leak remains at below the design basis rate, which reduces the time to core damage and postpones the release time to the point that Con Edison believes it would not be considered an early release.

Significance Determination Process:

The magnitudes of the yearly incremental CDF for an SGTR in the initial NRC ($1 \times 10^{-4}/RY$) and the preliminary Con Edison estimate ($.77 \times 10^{-4}/RY$) are relatively the same.

The new Con Edison calculation indicates a specific conditional CDF of 2.2×10^{-6} , with no LERF

The current guidance for assigning risk significance is contained in a draft NUREG/CR titled "Basis Document for Large Early Release Frequency (LERF) Significance Determination Process (SDP) - Inspection Findings That May Affect LERF." The Office of Research is sponsoring the project at Brookhaven National Laboratory that is developing this guidance. The guidance is summarized in Table 1 of that document as shown here.

Table 1 Risk Significance Based on LERF and CDF		
incremental CDF Range/ry	SDP Based on CDF	SDP Based on LERF
$\geq 10^{-4}$	Red	Red
$< 10^{-4} - 10^{-5}$	Yellow	Red
$< 10^{-5} - 10^{-6}$	White	Yellow
$< 10^{-6} - 10^{-7}$	Green	White
$< 10^{-7}$	Green	Green

Therefore, the CDF/LERF increment associated for a SGTR event is considered to be clearly above the $10^{-5}/RY$ criterion for a "red" significance determination. However the Con Edison assumption for lower than design SGTR leakage drops the CDF to 2.2×10^{-6} with no LERF - so this would be a white CDF finding with no LERF.

~~PREDECISIONAL INSPECTION INFORMATION
INTERNAL NRC STAFF USE ONLY~~

V. Potential Notices of Violations

10 CFR 50, Appendix B Criterion IX - Control of Special Processes and Criterion XVI - Corrective Actions, require, in part, that Con Edison, conduct an steam generator eddy current inspection program that promptly identifies and takes corrective actions for significant conditions adverse to quality.

Contrary to the above, Con Edison in 1997 failed to conduct a steam generator eddy current inspection program that promptly identified and took corrective actions for significant conditions adverse to quality. Consequently, a steam generator tube with detectable degradation was left in service following the 1997 refueling outage, eventually leading to the February 15, 2000, steam generator 24 tube row 2 column 5 failure. Specifically, Con Edison did not:

1. adjust the program to compensate for high noise signals in the low radius U-bend areas; these high noise signals negatively affected flaw detection capability;
2. take adequate corrective actions following identification of a new tube degradation mechanism, i.e., inside diameter (ID) primary water stress corrosion cracking (PWSCC) at the apex of a low radius U-bend tube;
3. establish a mechanism to monitor for and have an acceptance criteria for significant upper support plate flow slot hourglassing. Further, the potential existence and impact of upper support plate hourglassing on PWSCC flaws in the apex region of a low row U-bend tube was not assessed following the identification in 1997 of eddy current probe restrictions; and
4. ensure the use of properly qualified eddy current techniques. The U-bend plus-point eddy current probe, was not set-up with the proper calibration standard or with the phase rotation specified by the EPRI qualified technique sheet, which affected the probability of detection of U-bend indications.

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

EA:

Date of Panel: July 25, 2000

Licensee: Consolidated Edison Company of New York, Inc.

Facility/Location: Buchanan, New York

Docket No(s): 50-247

License No(s):

Inspection/OI Report No(s): 2000-010

Date of Exit Meeting/OI Report Date: July 20, 2000

Panel Chairman (SES Sponsor): Brian Holian

Responsible Branch Chief/Lead Inspector: David Lew/Wayne Schmidt

Enforcement Representative: Rick Urban

Other regional attendees: LATER

Headquarters attendees: LATER

References (attached):

1. Indian Point 2 Steam Generator Special Inspection Summary, dated July 21, 2000 - with attachments 1) NRC SDP; 2) Con Ed PSA Calculation, 3) Con Edison - Provided information on several inspection issues - provided July 20, 2000 - 11 am, 4) Con Edison disagreements with team findings - given by VP - Engineering - at the close of the exit on July 20, 2000 pm. 5) E-mail from NRR concerning initial review of the Con Edison PSA calculation.

1. Brief Summary of Issues/Potential Violations:

Severity Level III, White to Red finding is proposed. See Reference 1, Section V -Draft Notice of Violations.

It must be noted that Con Edison dias agrees with the teams conclusions as discussed in Reference 1 Attachments 3 and 4. Con Edison provided some technical detail that will be reviewed by team members prior to the issuance of the report.

2. Purpose of Panel:

Discuss the Special Inspection Team's summary of findings and conclusions document in Reference 1, Section 1.

Discuss and decide on the proper SPD assumptions for this event, see Reference 1, Section IV - Risk and Significance Assessment.

1

July 21, 2000 PREDECISIONAL INFORMATION
DO NOT DISCLOSE

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

Based on an initial review of EGM 96-003 Steam Generator Tube Inspections, Updated June 1, 2000 Case #6 appears to apply - Potential Severity Level III. The risk significance of the event is discussed below currently it ranges from a White (prelim. Con Ed) to Red (prelim. NRC).

3. Regional Recommended Strategy:

The proposed enforcement action is a Severity Level III Violation. The Initial NRC Significance Determination Process Red characterization is preliminary and based on a initial assumption of a SGTR with core damage and a large early release (LER) from a stuck open safety valve.

The Con Edison provided calculation based on assumptions for the day of the event to determine a CDF with a time profile greater than 50 hours, their assumption is that this does not result in an LER, but a release after the emergency plan has had time to act to protect the public.

A regulatory conference is recommended to discuss the performance issues and the CDF/LERF assumptions.

4. Analysis of Significance/Root Cause:

a. Actual Consequence(s):

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. No radioactivity was measured off-site above normal background levels and, consequently, the event did not impact the public health and safety. The licensee's 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 NRC 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.

b. Potential Consequence(s):

See Reference 1, section IV - Risk and Significance Assessment for a discussion of preliminary NRC and Con Edison review.

Reference 1, Attachments 1 and 2 provide the initial NRC and Con Edison reviews, respectively. NRR completed an initial review of the Con Edison PSA Calculation it is Attachment 3 to Reference 1.

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

c. Potential for Impacting Regulatory Process: LATER

d. Willful Aspects: None

e. Root Causes:

See Reference 1 - Section II - Conclusion/Root Cause

5. Apparent Severity Level(s)/Color and Basis:

See Section 2. above.

6. Application of Enforcement Policy

a. Enforcement/Performance History:

Indian Point 2 is an Agency Focus plant.

b. Is Credit Warranted for Identification? Explain:

Credit is not warranted for identification. The problem was revealed through the steam generator tube failure event of February 15, 2000. Con Edison did not:

1. adjust the program to compensate for high noise signals in the low radius U-bend areas; these high noise signals negatively affected flaw detection capability;
2. take adequate corrective actions following identification of a new tube degradation mechanism, i.e., inside diameter (ID) primary water stress corrosion cracking (PWSCC) at the apex of a low radius U-bend tube;
3. establish a mechanism to monitor for and have an acceptance criteria for significant upper support plate flow slot hourglassing. Further, the potential existence and impact of upper support plate hourglassing on PWSCC flaws in the apex region of a low row U-bend tube was not assessed following the identification in 1997 of eddy current probe restrictions.
4. ensure the use of properly qualified eddy current techniques. The U-bend plus-point eddy current probe, was not set-up with the proper calibration standard or with the phase rotation specified by the EPRI qualified technique sheet, which affected the probability of detection of U-bend indications.

c. Is Credit Warranted for Corrective Actions? Explain:

Credit is not warranted for Corrective Actions. Though the actions to correct the problem of

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

stopping the primary to secondary leakage and associated release of radioactivity to the environment, the corrective actions are not comprehensive and are still being reviewed by NRR. Additional corrective actions, such as plugging all row 3 steam generator tubes is under discussion. Issues related to Con Edison's Condition Monitoring and Operational Assessment of the event are not yet resolved.

The root cause provided by the licensee was inadequate as described Reference 1, Section III - Performance Issues

d. Should Discretion Be Exercised to Mitigate or Escalate Sanction?

There are three issues on the 'List of Issues That May Warrant Discretion' for consideration. See Attachment 2 for discussion.

7. Is action being considered against individuals?

No.

8. Non-Routine Issues/Additional Information/Relevant Precedent/Lessons Learned:

Generic communication may be needed for this issue regarding NRC expectations and observations related to the use of the EPRI Guidelines on steam generator eddy current testing, poor signal to noise ratios (high noise levels), the significance of top tube support plant hourglassing and U-bend/top support plate restrictions, and contractor oversight. NRR would provide any programmatic guidance deemed necessary.

July 21, 2000 PREDECISIONAL INFORMATION
DO NOT DISCLOSE

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

Attachment 1

SDP/Enforcement Panel Disposition Record

Licensee : _____
EA No. _____
Panel Date: _____
Issue: _____

Attendees

Chair - _____ Branch Chief - _____ Enf Reps _____
OI Rep. - _____ RI Counsel - _____ Others - _____
HQ Reps _____

Required Actions (Preliminary Proposed Actions - See OE Strategy Form for official record of panel decision.)

1)

Responsible Person: _____ ECD: _____

2)

Responsible Person: _____ ECD: _____

3)

Responsible Person: _____ ECD: _____

4)

Responsible Person: _____ ECD: _____

Examples of Specific Actions To Be Documented

- Call Licensee and Schedule Conf or give heads up on choice letter
- Prepare summary of OI findings as attachments to choice letter or conf letter
- Issue letters scheduling conference or providing choice
- Gather additional information and repanel
- Prepare the draft enforcement action
- Finalize the enforcement action

July 21, 2000 ~~PREDECISIONAL INFORMATION~~
~~DO NOT DISCLOSE~~

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

- Forward Package to OE

**SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure**

Attachment 2

ISSUES TO CONSIDER FOR DISCRETION

- Case involves particularly poor licensee performance. Yes**

- Excessive duration of the problem resulted in a substantial increase in risk. Yes**

- Discretion should be exercised by escalating or mitigating to ensure that any proposed civil penalty reflects the NRC's concern regarding the violation at issue and that it conveys the appropriate message to the licensee. Yes escalate**

The team found that Con Edison returned Indian Point, Unit 2, to service in 1997 in a condition that deteriorated with time to the point that a steam generator tube failure occurred.

The team concluded that during the 1997 steam generator inspection, Con Edison did not recognize and take corrective actions for significant conditions adverse to quality relating to eddy current data collection and analysis and specific steam generator conditions. These missed opportunities caused significant limitations and uncertainties, resulting in tubes with detectable flaws being left in service. Collectively, these opportunities, along with a new active degradation mechanism, increased the likelihood of tube integrity problems during the subsequent operating cycle. Since the plant is already an Agency Focus Plant escalation may not be needed.

~~July 21, 2000 PREDECISIONAL INFORMATION
DO NOT DISCLOSE~~