From: Patrick Milano , NRR
To: Steven Long , NRR
Date: 4/12/01 10:47AM
Subject: Answers to Q's

As you requested.

J/74

MEMORANDUM TO: Brian W. Sheron, Associate Director
for Project Licensing and Technical Analysis

FROM: Maitri Banerjee, Acting Chief, Section 1
Project Directorate I
Division of Licensing Project Management

SUBJECT: RESPONSE TO QUESTIONS REGARDING AUGUST 1999 AND FEBRUARY 2000 EVENTS, INDIAN POINT NUCLEAR GENERATING UNIT NO. 2 (TAC NO. MB0193)

On September 27, 2000, Scott Newberry, the Steam Generator Lessons-Learned Task Group Leader, received a set of questions related to several events at the Indian Point Nuclear Generating Unit No. 2 (IP2) that occurred in August 1999 and February 2000. The questions were not signed by the individual raising the concerns. Since these questions were beyond the charter of his group and were determined to not be allegations, the Executive Team requested the Division of Licensing Project Management coordinate a staff review. Thus, the attached response was prepared with inputs from the appropriate branches and Region I.

If you have any questions, please contact Patrick Milano at 415-1457.

Docket No. 50-247

Attachment: Response to Questions
Regarding IP2 Events

Technical Points of Contact:

S. Long, SPSB	T. Frye, IIPB	R. Jenkins, EEIB	S. Barber, RGN-I
415-1077	415-1287	415-2985	610-337-5232

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RESPONSE TO UNSIGNED SET OF QUESTIONS RELATED TO THE AUGUST 1999 AND FEBRUARY 2000 EVENTS AT INDIAN POINT NUCLEAR GENERATING UNIT NO. 2 (IP2)

Question 1:

> How reasonable are the IP2 calculations? - The first event discovered latent failures that were not picked up during surveillance testing or maintenance. Also, first trip was "spurious," it was only "luck" that trip occurred before the tube rupture event occurred. (There was no other reactor trip in between these two events.) Had the latent failures in the plant on August 15, 1999 not been corrected, then it is probable that the manual trip in response to the SGTR [steam generator tube rupture] would have triggered a LOOP [loss of off-site power] and the lockout of one EDG [emergency diesel generator] for the same "mechanistic" reasons, making the SGTR event much more difficult to control.

Response:

In order to respond fully to this question, it is appropriate to first consider what analyses were performed and what was left out, and then to decide what the effect would have been if the additional factors had been included.

What calculations were done:

For specific events, the Office of Research (RES) calculates the conditional core damage probability (CCDP), but not the conditional large early release probability (CLERP) as part of the Accident Sequence Precursor (ASP) Program. NRR calculates the deltas in core damage frequency (ΔCDF) and large early release frequency (ΔLERF) for off-normal conditions identified by inspection activities.

RES performed two CCDP calculations for the two events at IP2. One evaluated the CCDP for the August 1999 LOOP event. When it was determined that the tube was weak during the LOOP event, the CCDP was reevaluated to consider the potential for SGTR to complicate the sequences that would lead to core damage and make them more likely, but there is not much effect on the overall CCDP. No attempt was made to calculate the CLERP, but the RES analyst does agree that the tube degradation that existed at the time of the event would increase the fraction of the CCDP that is CLERP.

RES also calculated the CCDP for the February 2000 steam generator tube failure (SGTF) event. RES did not attempt to include the effects of an elevated potential for a LOOP and potential station blackout (SBO) following reactor trip due to the conditions revealed by the previous spurious trip event. If that were to be included, it would require some evaluation of the probability for the February event to be the first trip since the miscalibration set up the consequential LOOP upon trip. A logical way to do that would be to use $1-e^{-\lambda t}$ where λ is the trip frequency and t is the period between the calibration problem and the SGTF event. On the other hand, if the flaw that was missed happened to be weaker when the inspection occurred, it could have failed sooner, compared to the miscalibration event. Perhaps 0.5 is as close as we

can get to the probability that these two problems would have compounded each other in a single event.
Region I, recognizing the potential for interaction of the two conditions, did attempt to calculate a CCDP and CLERP for a *hypothetical* event in which the LOOP conditions of the August event were assumed to occur following the trip associated with the February SGTF event. The effect was not great (39% increase) because the actual failures during the August LOOP event did not preclude mitigation of the February SGTF event. This calculation did include the effects of complications such as increased human error rates due to greater complexity and operator stress levels. It did not include some of the factors that RES has considered that lower the final results, so this numerical result is more useful from a relative importance perspective. If we apply a factor of 0.5 to account for the probability of the events occurring together, the effect would be only about a 20% increase in the CCDP and CLERP for the tube failure, alone.

As part of the Significance Determination Process (SDP), NRR estimated a ΔCDF for the last year of the period of operation with the degraded tube strength. This estimate included the potential for spontaneous rupture, pressure induced rupture and thermally induced rupture on CDF and LERF. However, this calculation did not include the higher frequency for core damage due to SBO from the conditions that existed until they were revealed by the August trip and LOOP event. Including it would substantially affect the ΔLERF calculation, but insignificantly affect the ΔCDF results. If this calculation had used the "high/dry" portion of the (current draft) ASP CCDP for the LOOP event, rather than the normal LOOP contribution to CDF, it would have estimated a "high-dry" CDF of at least 4.6×10^{-5} for the last year of plant operation, instead of the 1-to-2 x 10^{-5}/RY value that was used in the significance determination process.

<u>Do these calculations adequately capture the risk of the plant operations</u>:

The questions raise the issues: (1) would it change our regulatory decisions for this situation at this plant if we had include these combined effects more fully, and (2) could concurrence of two conditions be important factors for other regulatory decisions at other plants?

It is clear that, for IP2, the resulting findings under the new Reactor Oversight Process (ROP) put the plant into a category of a plant with "multiple degraded cornerstones," so the method used did not result in an under-response in this case. If the weakened tube was included in the SDP for the LOOP event, it would have produced a ΔLERF that would have been in the "red" range had the ROP been implemented at that time. If the SBO frequency implications of the LOOP event were included in the SDP for the tube failure event, the range of results for the sensitivity case analysis would have been entirely within the red range, instead of bracketing the red/yellow threshold.

When multiple issues stem from the same (common) cause, risk analysis techniques account for the potentially greater risk significance of the combined issues (i.e., ΔCDF or ΔLERF). However, the ROP Action Matrix was designed to combine multiple issues for determining the appropriate NRC response. Although the regulatory response is not expected in most cases to differ if multiple issues are treated either in combination or independently, the ROP guidance is being evaluated for enhancement regarding the application of combined risk results of multiple issues in a manner appropriate for use in the ROP Action Matrix. As discussed in the response to Question 4, the written SDP procedures currently make it clear that the intent is to consider the combined risk significance of concurrent conditions, to the extent that it is appropriate and feasible to do.

Question 2:

> Will grid deregulation lead to more events where LOOPs are caused by reactor trips? - Plant under-voltage settings are determined based on expected grid response following certain known contingencies. In a deregulated environment, how can we assure proper coordination of plant under-voltage protection when power generation and grid operation are no longer under the control of the reactor licensee. Reactor plant operator, who no longer control how the grid is run, may not have the information available of the grid calculational model to know if they are running in a condition which would result in LOOP given trip. And even if they did, they may not have the authority to get the grid operator to make the necessary adjustments to compensate.

Response:

The August 31, 1999, event involved a reactor trip with complications from various system interactions that included safety-related equipment. The cause of the reactor trip was a spurious signal from the Over-Temperature Delta-Temperature (OTΔT) process instrumentation. The LOOP condition occurred because the station auxiliary transformer load tap changer (LTC) was incorrectly placed in the "manual" position. The LTC control setting led to an extended voltage drop on the 480 volt buses, causing actuation of degraded voltage relays and a LOOP to the safety buses. The Augmented Inspection Team (AIT) found that if the LTC had been placed in the "automatic" control setting the voltage response from the transformer would have mitigated the voltage transient, returning the bus voltage to normal in sufficient time to prevent the LOOP condition. Further, the "automatic" control setting for the LTC is required per the plant's licensing basis. Plant undervoltage settings are determined not by the expected grid response but the expected range of voltage necessary to power safety-related equipment. An undervoltage or degraded voltage condition can lead to premature equipment failure and the inability of the subject equipment to perform its intended safety function(s).

The February 15, 2000, event involved a SGTF which led to a manual reactor trip. Offsite power or grid reliability was not applicable to the subject event.

Although we do not anticipate that deregulation will lead to a degradation of offsite power reliability, the staff is monitoring industry developments which may potentially affect offsite power capability. Recently, the NRC issued Regulatory Information Summary (RIS) 2000-24, "Concerns About Offsite Power Inadequacies and Grid Reliability Challenges Due to Industry Deregulation," on December 21, 2000, to alert stakeholders to possible concerns regarding the voltage adequacy of offsite power sources. This RIS documents actions the industry has committed to take in order to address this issue.

Question 3:

> Were the AIT charters on IP2 events too limited? - Although the LOOP was the result of a voltage dip following the reactor trip and may be an indicator of generic concerns about grid voltage behavior, no data on the voltage levels was

collected. Current risk calculations do not consider increased likelihood of LOOP due to reactor trip. The focus on the tap changer diverted the investigation from the more real safety concern- that plants may be subject to more severe voltage drops following a trip than was the case before deregulation.

Response:

The content of the AIT charters is constructed based on the information that is available when dispatching the team. NRC Inspection Manual Chapter 0609 provides a sample charter which may be used when constructing for a wide variety of plant events. The charters tend to allow a fair amount of latitude and are not overly restrictive. Thus, the region would not consider the charter too narrow for either the August 1999 or the February 2000 event.

The LOOP was caused by the incorrect position for the station auxiliary transformer (SAT) tap changer. Since the tap changer was in manual, it did not "step up" the SAT voltage when it was appropriate. The recovery of on-site power was complicated by the trip of the affected EDG and subsequent lockout of all 480 volt safety busses. The lockout was the overriding factor that complicated plant recovery, not the initial LOOP.

The LOOP was not caused by the reactor trip. It was caused by the incorrect position for the SAT tap changer. This was a configuration control error made by the licensee that could exist before or after deregulation.

As stated in the response to Question 2, the cause of the LOOP during the August event was due to plant-specific factors. Therefore, no direct relationship can be attributed to grid voltage behavior or industry deregulation. It should be noted that the generic concerns stated in the question are being pursued under an NRC-NEI Industry Initiative on Grid Reliability. The principal safety concern addressed by this initiative is the maintenance of the licensing and design basis for offsite power to nuclear plants which includes the capability of plant equipment to survive expected voltage transients and to perform its intended safety function(s).

Question 4:

Is the revised reactor oversight process faulty with it's focus on a single event? - Isn't it a better indicator of the overall plant performance to include some recent past history? A "good performer" would be much less likely to have two events in a row that had significance. IP2 may be one of the worst "combination" of events ever. It wouldn't be a major effort to look back on [a] previous trip or two at a plant involved in a potentially serious event.

Response:

The new reactor oversight process (ROP) is not focused on a single event, and does use recent plant history as an overall indication of plant performance. Through the use of an "Action Matrix," the assessment process integrates numerous inputs reflecting recent plant history to identify declining licensee performance that warrants increased NRC interaction. The inputs to the "Action Matrix" include both performance indicators (PIs) and inspection findings.

Each of the 18 PIs included in the ROP are based on at least 12 months of data to calculate the indicator, with several of the indicators based on 24 or 36 months of data. This allows recent plant events and issues to be integrated in a meaningful way, with the data applied against risk-informed thresholds to indicate when additional agency action is warranted. For example both the August 1999 and February 2000 reactor trips were counted in the Unplanned Scrams PI, and resulted in this PI crossing the Green/White threshold for the 2nd quarter 2000, indicating the need for increased regulatory oversight above the baseline inspection program.

In addition, each inspection finding is evaluated through the SDP to characterize the risk significance of the issue. The SDP does require that concurrent performance deficiencies be assessed collectively to determine the total contribution to ΔCDF. This allows the collective assessment of a combination of different deficiencies that, although they may have been discovered at different times, occurred concurrently and impacted licensee performance. Although this had always been the intent of the SDP, this guidance was not clearly described until it was included in a recent revision to inspection manual chapter 0609, "Significance Determination Process", dated December 28, 2000, following the evaluation of the February 2000 SGTF. The staff is continuing to evaluate the need for additional changes to the SDP procedure to further define an appropriate approach to characterize the significance of such findings and use them as inputs to the ROP assessment process.

The evaluation of the August 1999 LOOP event determined that this would likely have been a Yellow finding, with substantial safety significance, had it occurred under the revised ROP. The SDP evaluation of the February 2000 SGTF determined that this was a Red finding, with high safety significance and a significant reduction in safety margin. Subsequent to the SGTF and the identification of degraded steam generator tubes, the staff re-evaluated the conditional core damage probability (CCDP) for both the LOOP and SGTF events to include the potential for either event to have occurred during, and complicated, the other event. The staff concluded that there would not have been a significant change to the CCDP for either event. Including the degraded tubes in the SDP for the LOOP does result in a change in the large early release frequency (ΔLERF) for the August 1999 event, and would have resulted in a Red finding instead of a Yellow. However, this would not have changed the NRC's response or involvement at IP2

due to the numerous other significant performance issues that were identified and applied to the assessment process.
The assessment process uses the "Action Matrix" to integrate these PI and SDP results and determine the appropriate level of NRC interaction based on these indications of licensee performance. The assessment process uses a 12-month rolling window of data to allow the accumulation of risk-significant issues, which may be indicative of systemic and pervasive breakdowns in licensee performance. As described in the IP2 Assessment Follow-up letter dated October 10, 2000, the PI and inspection finding data collected over the previous year indicated that several cornerstones of safety were degraded, principally associated with the August 1999 reactor trip and the February 2000 SGTF. As directed by the "Action Matrix," this resulted in the conduct of several NRC activities above the baseline level of oversight, such as monitoring the licensee's performance improvement plan and the conduct of an independent team inspection to diagnose the breadth and depth of the safety, organizational, and programmatic issues that led to the degraded cornerstones of safety.