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Subject:

X/25

On August 31, 1999, the reactor inadvertently tripped while the licensee was replacing a defective bi-stable in a pressurizer low pressure instrument channel. After the reactor trip, the station blackout logic matrix generated a blackout signal as a result of a sustained under-voltage condition at the safety-related 480-V buses. The station blackout signal stripped the 480-V buses and reloaded them onto the emergency diesel generators (EDGs). The EDG output breaker to the 480-V bus 6A tripped within 14 seconds after closing due to an over-current condition on the bus.

Two conditions led this event. They are: (a) a defective voltage control relay, and (b) a wrong set point of the EDG 23 output breaker.

Since both of these conditions existed at IP-2 for a period of time, we examined all LERs reported by IP-2 over a two year period from 8/31/98 to 8/31/2000 to find out how other conditions which co-existed may have affected IP2's CDF over the period between 8/31/98-8/31/99.

Based on LER review, we found two LERs. One which reported a steam generator tube leak and the second LER which reported a fuel oil leak in the cylinder no. 8 of EDG-21. In combination of the two conditions which resulted in LER 247-99-015 on the loss of offsite power event, we concluded that, under worst case, between the period 8/31/98-8/31/99, any reactor trip could have lead to a loss of offsite power, failure of EDG-23 (due to tripping of EDG-23 output breaker), and failure of EDG-21 (due to fuel oil leak).

After additional discussions with the licensee, we determined that the condition which lead to EDG-23 output breaker failure co-existed with other conditions from 7/1/99-8/31/99 (only two months). Furthermore, since this was easily recoverable, the impact was low. Additional investigations on LER 247-98-019 and discussions with cognizant EDG experts lead to the conclusion that, EDG-21 was degraded but function. The risk associated with the potential SGTR after a LOSP was determined to be negligible (basis provided in next page).

When we quantified the increase in CDP was over the one-year period between 8/31/98-8/31/99 to determine risk of increased likelihood of LOSP over this period, it was less than the CCDP associated with the event (1.1E-04), in order to prevent any double counting of risk, we did not include this in our analysis.

A consequential steam generator tube rupture could have increased the risk associated with this event. As demonstrated below, the impact of the degraded steam generator tube on the CCDP associated with this event is negligible.

In order contribute to CCDP, the probability of one of the following sequences must be significant compared to the CCDP associated with the loss of offsite power event itself.

Sequence 1: Failure to control reactivity introduces additional stresses on the degraded steam generator tube

This sequence consists of the following events:
- Reactor trip function fails;
- Degraded steam generator tube fails as a result of additional stresses of ATWS;
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 2: Failure to introduce AFW causes dry out of steam generator and introduces additional stresses on the degraded steam generator tube

This sequence consists of the following events:
- AFW fails;
- Feed and bleed cooling fails;
- Degraded steam generator tube fails due to steam generator dry out; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 3: Secondary side pressure reduces rapidly due to main steam line break while the primary pressure stays high

This sequence consists of the following events:
- Main steam line break;
- Rapid secondary side depressurization leads to a steam generator tube rupture; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 4: Secondary side pressure reduces rapidly due to stuck-open steam generator relief valve while the primary pressure stays high

This sequence consists of the following events:
- Primary side heat removal degrades and consequently RCS pressure stays high;
- Secondary side pressure increases and challenges a steam generator relief valve;
- Secondary side relief valve sticks open and depressurizes secondary side;
- Degraded steam generator tube fails; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 5: <u>Primary pressure increases as a result of the failure of all AC power and relief valves fail to lift</u>

This sequence consists of the following events:

- All AC power is lost;
- RCS pressure increases;
- Pressurizer relief valves fail to lift;
- Degraded steam generator tube fails; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Of the five sequences stated above, Sequence 1 is negligible due to the low likelihood of an ATWS at a Westinghouse plant—7×10^{-7} per year (Ref. 16).

Since the feed and bleed function was unavailable during the event, Sequence 2 has already been included as a core damage sequence (except, consequential steam generator tube rupture may increase the conditional large early release probability via this sequence).

Sequence 3 is negligible because of the low likelihood of a main steam line break during the 24 hour mission time of an accident. Based on Ref. 17, the frequency of a main steam line break outside containment is 3×10^{-4} per critical year. Therefore, the probability of this event over a 24 hour period on the affected steam generator is approximately 8×10^{-7}.

Sequence 4 has a negligible contribution to the total CCDP due to the following. On August 31, 1999, when power was lost to the emergency buses, the power remained available to the balance-of-plant systems used for condenser heat removal. Therefore, the likelihood of steam generator pressure increase and a challenge of steam generator SRV requires the loss of condenser heat sink following the reactor trip. From data from Ref. 14, the total probability of loss of condenser vacuum, turbine bypass capability, or isolation of all main steam isolation valves is 5×10^{-2}. Assuming that one SRV opens on the faulted steam generator, although the atmospheric dump valve is sized for decay heat removal, from the IPE, the probability of the valve failing to close is 9×10^{-2} (Ref. 9). Conservatively assuming that the faulted tube will rupture due to the depressurization of the steam generator, the CCDP for a steam generator tube rupture during the loss of offsite power event is 2×10^{-6} [$=(5 \times 10^{-2}) \times (9 \times 10^{-2}) \times (4 \times 10^{-4})$; where 4×10^{-4} is the CCDP for a classical steam generator tube rupture from the SPAR model for Indian Point 2). This contributes to about 2 percent of the CCDP.

Sequence 5 is negligible, since the product of the probability of the relief valves failing to lift and the probability of failing all AC power is low.