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U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: Duke Power Company
McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nulear Station
Docket Numbers 50-413 and -414
Topical Report DPC-3002, "FSAR Chapter 15 System Transient Analysis Methodology";
Reponse to NRC Questions

On July 18, 1994 Duke Power Company sub. itted Revision 1 to the subject topical report for review and approval. By letter dated July 25, 1995, the NRC staff requested additional information about the report. Attached are responses to the Staff's questions.

If you have any questions, or need more information, please call Scott Gewehr at (704) 382-7581.

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Attachment

Question 1

Explain the new sentence in §2.2.3 (increase in feedwater flow). Is DPC saying that a decrease in MFW temperature is a surrogate for the increased flow or that both are assumed to occur.

Response

Both an increase in the main feedwater flow and a corresponding decrease in temperature are assumed to occur. The magnitude of the temperature decrease is conservatively calculated based on maintaining a constant heat addition rate from the feedwater heaters.

Question 2

Explain the reason why DPC's assumption regarding the PZR level control shifted from the automatic to the manual operation for the turbine trip analysis (§3.1.1.4).

Response

This revision corrects a typographical error in the original report. The turbine trip analyses for both the feedring and preheater steam generator designs were performed assuming that the pressurizer heaters are manually locked on. This augments the pressurizer pressure increase which conservatively delays reactor trip on overtemperature ΔT.

Question 3

Clarify the SG level control description for the turbine trip.

Response

This question concerns analysis methodology which has not been revised. In the turbine trip analysis, main feedwater flow is conservatively isolated at the initiation of the transient. If feedwater flow were to continue, a portion of the primary system heat would be expended heating the subcooled feedwater up to saturation conditions as opposed to generating steam. This would act to reduce the secondary system pressure, which is non-conservative for all acceptance criteria.

Question 4

Explain the qualification on availability of the purge volume of hot MFW for the Loss of Non-Emergency AC Power Event (§3.2.1).

Response

As it is used here, "purge volume" refers to the amount of relatively hot main feedwater that must be displaced from the auxiliary feedwater piping before the cold auxiliary feedwater can reach the steam generators. This purge volume is introduced because of the delivery of a small percentage of the main feedwater flow through the auxiliary feedwater piping and associated nozzles during steady-state full power operation. Plant operations staff at McGuire has eliminated this tempering flow practice, while Catawba has not. Therefore, the purge volume modeling is applicable only to Catawba analyses.

Question 5

Explain why the high instead of low initial SG level is conservative for the ability to establish natural circulation (§3.2.4 - loss of non-emergency AC power).

Response

As stated in the report, the high initial level assumption minimizes the volume of the steam space in the steam generator. Following turbine trip, this smaller steam volume yields a greater pressurization rate. The higher steam generator pressure (and saturation temperature) conservatively reduce the primary-to-secondary heat transfer.

Low steam generator level would be conservative only if the primary-to-secondary heat transfer were degraded by tube bundle uncovery prior to the point at which the auxiliary feedwater heat removal capacity exceeds the core decay heat generation. Beyond this point, the transient turns around and primary system temperatures begin to decrease.

In the existing analysis, this transition point is reached approximately 10 minutes after the loss of offsite power. At that time, the steam generator liquid mass has decreased by less than 15,000 lbm from its initial value of approximately 130,000 lbm. At this point in time, there is a large amount of margin to tube bundle uncovery and heat transfer degradation. This conclusion would remain valid even if the initial steam generator level was adjusted low rather than high.

Question 6

§3.2.5.1 of Ref. 2 does not describe the turbine control. Please revise reference.

Response

Automatic turbine control is modeled in RETRAN as a negative fill junction with a constant flow rate, as described in §3.2.5.1 of DPC-NE-3000. This simulates the modulation of the turbine control valves which act to maintain a constant turbine power and, therefore, a constant steam flow rate.

Question 7

Discuss and justify the timing of reactor trip in §3.3 (loss of normal feedwater). In addition, DPC should provide demonstration that both the RCS and SG pressure peaks are higher and the DNB is lower with earlier reactor trip with less mass in SG than with delayed trip. Discuss how the low-low level trip setpoint is adjusted.

Response

The loss of feedwater transient has been determined to be bounded by the turbine trip event and is not routinely analyzed as part of the DPC licensing basis analyses. A reanalysis is performed with the feedring steam generators for the purpose of generating replacement FSAR figures.

Before a discussion of the trip setpoint adjustment can proceed, three basic terms must be defined: nominal, indicated, and actual level. Nominal level is the programmed value at which the plant is intended to operate. Indicated level refers to the control room indication, which may vary within a specified controller deadband around the nominal value. The actual level is the true water level in the steam generator, which can differ from the indicated level by the measurement uncertainty of the level instrument.

The intent of the downward adjustment to the steam generator level was to promote the uncovery of the tube bundle, as this would potentially degrade the primary-to-secondary heat transfer. If the initial level indication were adjusted upward, reactor trip on low-low steam generator level would be delayed. However, this also introduces competing effects. The delayed reactor trip would extend the RCS heatup but also the core power reduction due to moderator temperature feedback. Since this event is bounded by the turbine trip event, a demonstration of the limiting initial steam generator level condition is not necessary. Were this accident to become potentially limiting in the future, a sensitivity study would be performed on the initial steam generator level assumption to ensure its conservatism.

In the analysis of the loss of feedwater transient, the actual level was initially set 8% below the nominal programmed value. This allowance is a statistical combination of the controller deadband and instrument uncertainties. Although inherent in this assumption is the fact that the indicated level must be lower than nominal, it is conservatively assumed that the indication is at the nominal value - fully 8% above the actual value. Physically, the reactor trips when the indicated value reaches the plant trip setpoint. In this RETRAN simulation however, the trip is modeled as if it occurred on actual level. Therefore, the reactor trip occurs when the actual level reaches a value 8% below the low-low steam generator level trip setpoint.

Question 8

Describe in detail the long-term core cooling analysis of the Feedwater System Pipe Break event with revised transient assumptions and scenario. When and on which signal is the turbine assumed to trip? Furthermore, discuss any impact from planned SG replacement on this transient analysis with respect to transient objectives, assumptions and scenario.

Response

The major impact of the feedring steam generators on this analysis is due to the design and location of the main feedwater nozzles. Since the main and auxiliary feedwater nozzles are now at approximately the same elevation, it is conservatively assumed that the auxiliary feedwater enters and exits the faulted steam generator without passing over the tube bundle and removing primary system heat. This is a significant departure from the preheater steam generator response, where the auxiliary feedwater delivered to the faulted generator must remove a significant amount of heat prior to exiting through the break. Therefore, in the feedring steam generator analysis it is conservative to assume a late operator action time for the isolation of the faulted generator.

In addition, since the main feedwater nozzle is considerably closer to the normal steam generator water level, following a short period of liquid blowdown the broken feedwater line is relieving steam instead of water. This tends to exacerbate the overcooling phase of the feedline break transient, which continues until the faulted generator has blown dry.

A third notable impact of the feedring steam generators is due to the lack of a flow-restricting orifice in the main feedwater nozzle. Because of this design difference, the faulted generator blows dry in roughly two-thirds of the time taken by the preheater steam generator.

In lieu of performing a revised containment response calculation to determine the timing of the high-high containment pressure signal actuation, the following modifications were made to the transient analysis assumptions. A loss of offsite power, which causes the reactor coolant pumps to coast down, is assumed to occur coincident with reactor trip on high containment pressure safety injection. The pumps were previously assumed to be tripped manually on high-high containment pressure. Also, steam line isolation is assumed to occur coincident with turbine trip, which occurs on reactor trip with no response time delay. The superseded analysis methodology assumed that steam line isolation occurred automatically on high-high containment pressure. In both of the above cases the revised assumption is more conservative than that which it replaces. Since, due to the feedring steam generator design, the overheating transient is less limiting, these modifications do not introduce any excessive conservatism.

Question 9

The RCP Locked Rotor event is proposed to be analyzed using the SCD methodology. Discuss the applicability of the SCD methodology for this event analysis.

Response

The approved DPC core thermal-hydraulic statistical core design methodology, including the range of applicability, is described in DPC-NE-2005P-A. Although the core inlet flow for the locked rotor transient falls below the minimum SCD parameter value, a statistical Monte Carlo propagation was performed to ensure that the statistical design limit (SDL) remained acceptable. The details of this statistical propagation methodology are discussed in §2.3 of the topical report. Using the BWCMV CHF correlation, the statistical analysis for the locked rotor transient yields a statepoint DNBR of 1.364, which confirms that the use of this correlation with an SDL of 1.40 is valid for this event.

Question 10

Discuss the impact of allowing a possibility of reactor trip on pressurizer high pressure for the analysis of the uncontrolled bank withdrawal from a subcritical or low power startup condition event.

Response

The subject revision simply includes a potentially applicable reactor trip function that was inadvertently omitted from the original report. The actual analysis methodology for the uncontrolled bank withdrawal from a subcritical or low power startup condition event has not been modified.

Due to the rapid increase in neutron power once prompt criticality is achieved, a high pressure trip is much less likely than a high flux trip. However, if the analysis is performed with a lower reactivity insertion rate, it is possible that the core power increase might be slow enough to allow a high pressure reactor trip.

Question 11

Since DPC is taking exception to the SRP guidelines with respect to the pressurizer overfill (for the inadvertent operation of ECCS during power operation transient), DPC should demonstrate that the analysis with the plant at zero power does produce more conservative PZR overfill analysis than does at the full power. Furthermore, discuss DPC's acceptance criterion for this event analysis.

Response

The Standard Review Plan stipulates that the Condition II inadvertent operation of ECCS during power operation transient not give rise to a more serious Condition III event. A potential escalation scenario that could result in an unisolable small-break LOCA involves the failure of the pressurizer safety valve to reseat following the relief of subcooled liquid.

According to Westinghouse VIL W 93-18, in order to meet the applicable Condition II criterion, the PSV's must either not open or must be capable of closing after release of subcooled water. DPC mechanical maintenance support staff has affirmed that the PSV's will reseat if the liquid relief temperature remains above 500°F. This low temperature limit is therefore chosen as the acceptance criterion for the event.

Zero power is chosen rather than full power as the initial condition for the analysis since the RCS is at a lower average temperature and would therefore have a lower transient temperature response.

Question 12

Discuss any impact of feedring SG design on the SG Tube Rupture analysis. DPC needs to justify extending the SGTR methodology approved for Catawba on McGuire applications. Provide discussion of the expected primary loop subcooling during the entire time of analysis. Discuss the impact of modified PZR modeling on the PZR pressure. In the plant nodalization, discuss the impact of the PZR on the affected vs. unaffected loops. In addition, DPC should justify the applicability of the SCD methodology for this event analysis.

Response

There are three significant effects of the feedring steam generators on the SGTR analysis. First, the feedring steam generator tubes are approximately 10% smaller in diameter, which yields a proportionally lower break flow rate. This introduces the competing effects of slower buildup of activity levels in the faulted steam generator and delayed recovery of the tube bundle. Secondly, the tube bundle in the feedring steam generator is approximately 8 feet taller than the preheater steam generator; therefore there is the potential for a greater period of tube uncovery. Tube bundle uncovery has a direct bearing on the entrainment of the break flow liquid droplets, which significantly impacts the activity of the steam released to the atmosphere. Thirdly, the feedring steam generator liquid mass at full power is approximately 20,000 lbm greater than that in the preheater steam generator. This equates to a larger liquid volume available for mixing with the break flow and diluting the iodine concentration of the steam relief.

The current approved methodology for McGuire is a non-mechanistic calculation which simply postulates 30 minutes of primary-to-secondary break flow with no thermal-hydraulic transient simulation. Applying the methodology which has been approved for Catawba to the McGuire analysis is both a more physical and more conservative approach. Three of the more significant areas of increased conservatism are: a) the primary-to-secondary break flow continues until the system pressures are equalized, b) the atmospheric release from the secondary system persists until the failed steam line PORV is isolated, and c) tube bundle uncovery is explicitly modeled (as discussed above). Finally, since the McGuire units will be virtually identical to Catawba Unit 1 following the steam generator replacement, the extension of the approved Catawba methodology is technically warranted.

Following the tube rupture, the RCS subcooling margin gradually decreases as RCS pressure decreases until reactor trip occurs. At this point, the RCS is still in a subcooled condition. During the cooldown portion of the transient, the subcooling margin gradually increases since the rate at which the RCS temperature is decreasing more than compensates for the rate at which the RCS is depressurizing. After the operators begin depressurizing the RCS to terminate break flow, the subcooling margin decreases, but always remains above 0°F. Following identification of the ruptured SG, cooldown of the RCS is initiated using the operable SM PORVs on the intact SGs. This cooldown continues until the RCS reaches a 20°F subcooled condition relative to the ruptured SG pressure. 10 minutes after this condition has been reached, operators begin depressurizing the RCS using a single pressurizer PORV until break flow is terminated.

Per §7.1.1, the local conditions heat transfer model was employed in the pressurizer in the original analysis methodology. This sentence is being removed from all of the event-specific discussions since the modeling is now applied generically as discussed in §3.2.3.3 of DPC-NE-3000. However, since this transient mainly consists of a prolonged pressurizer outsurge, the wall conductors do not play a significant role.

Since an outsurge of hot water from the pressurizer will occur as the RCS depressurizes during this event, the pressurizer is assumed to be attached to the lumped intact loops. This will maximize the break flow through the ruptured tube by minimizing the primary inlet temperature entering the ruptured steam generator.

The tube rupture DNBR transient, which is analyzed completely independent from the offsite dose analysis, is essentially a complete loss of reactor coolant flow event initiated from a reduced pressurizer pressure. At the minimum DNBR statepoint, all of the SCD treated parameters: core inlet temperature and flow, core exit pressure and core heat flux are within their respective parameter ranges for SCD applicability (Refer to Appendix B of DPC-NE-2005P-A).

Question 13

DPC should revise §9.0 (References) in Revision 1.

Response

When Revision 3 to DPC-NE-3000 is approved, the references will be updated accordingly.