UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

April 2, 2004

EA-04-017

Carolina Power and Light Company
ATTN: Mr. C. J. Gannon
Vice President
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P. O. Box 10429
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SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A GREEN FINDING (NRC INSPECTION REPORT NO. 05000324/2004007, BRUNSWICK STEAM ELECTRIC PLANT)

Dear Mr. Gannon:

The purpose of this letter is to provide you with the Nuclear Regulatory Commission's (NRC) final significance determination for a finding involving the design review of a modification implemented on Brunswick Steam Electric Plant's (BSEP) Unit 2 reactor feed pump (RFP) speed control system. The finding was documented in NRC Inspection Report 05000324/2003006, issued on January 16, 2004, and was assessed under the significance determination process as a preliminary White issue (i.e., an issue of low to moderate safety significance, which may require additional NRC inspection). In a letter, dated January 27, 2004, subject, Preliminary White Finding, we informed Carolina Power and Light Company (CP&L) of the NRC's preliminary conclusion, provided CP&L an opportunity to request a regulatory conference on this matter, and forwarded the details of the NRC's preliminary estimate of the change in core damage frequency (CDF) for this finding. At CP&L's request, an open regulatory conference was conducted on March 17, 2004, to discuss CP&L's position on this issue. This conference was summarized in an NRC Region II letter, dated March 23, 2004.

During the conference, CP&L presented its evaluation of the cause of the RFP speed control design error, corrective actions, and the results of its estimate of the increase in CDF due to the performance deficiency. CP&L's estimate of the increase in CDF was approximately one order of magnitude lower than the NRC's estimate, as documented in our January 27th letter. The lower estimate was due, in part, to the identification of recovery actions to provide main feedwater supply if high pressure coolant injection fails, and revised initiating event data for postulated turbine trips and loss of feedwater events. These assumptions and inputs were different from those used in the NRC's estimate, which assumed that main feedwater would not be recoverable if high pressure injection failed, and assumed that all transients causing a main generator trip would lead to a loss of feedwater. Based on this, CP&L concluded that the finding was of very low safety significance (Green).

After considering the information developed during the inspection, the information provided in CP&L's letter of March 9, 2004, and the information CP&L provided at the conference, the NRC has concluded that the final inspection finding is appropriately characterized as Green for

Unit 2, in the Mitigating Systems Cornerstone, as indicated in the enclosed Post-Conference SDP Phase III Summary. In summary, CP&L presented plant specific information at the conference regarding the likelihood of main feedwater recovery during certain transients in which high pressure injection is available and main steam isolation valve closure is not expected. The contribution of main feedwater recovery for these postulated accident sequences was sufficient to reduce the change in CDF to the Green threshold. This plant specific information had not been developed at the time of the NRC's preliminary estimate.

Our January 27th letter did not explicitly address the impact of Large Early Release Frequency (LERF) on this issue. Subsequent to the conference, the NRC also confirmed that the RFP speed control system deficiency had a minimal effect (Green) on the increase in the LERF.

You have 30 calendar days from the date of this letter to appeal the staff's determination of significance for the identified Green finding. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, Attachment 2. You are not required to respond to this letter unless the description herein does not accurately reflect your position, or if you choose to provide additional information.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (should you choose to provide one) will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), which is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, any response should not include any personal privacy, proprietary, classified, or safeguards information so that it can be made available to the Public without redaction. The NRC also includes significant enforcement actions on its Web site at www.nrc.gov; select What We Do, Enforcement, then Significant Enforcement Actions.

Should you have any questions regarding this letter, please contact Paul Fredrickson, Chief, Reactor Projects Branch 4 at 404-562-4530.

Sincerely,

/RA/ (By) Leonard D. Wert

Victor M. McCree, Director
Division of Reactor Projects

Docket No.: 50-324
License No.: DPR-62

Enclosure: Post-Conference SDP
Phase III Summary

cc w/encl: (See page 3)

cc w/encl:
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SRA Analysis Number: BRU0301Rev1
Analysis Type: SDP Phase III
Inspection Report #: 05000324/2004007.
Plant Name: Brunswick
Unit Number: 2
Enforcement Action: EA-04-017

This Phase 3 is the post conference evaluation.

I. Background - During the Spring 2003 Unit 2 outage, the licensee implemented a modification to the reactor feed pump speed control system. This modification, EC 46822, replaced the existing mechanical-hydraulic speed control system with a digital speed control system (Woodward TMR 5009). During follow-up of issues raised during the November 4 Unit 2 reactor trip, the licensee determined that a trip of both reactor feed pumps would occur during a Unit 2 turbine trip. The licensee discovered that the digital speed control system power supplies (two for each reactor feed pump) were designed to sense a fault condition within one cycle of abnormal supply voltages. The power supplies would fault, and thus cease to supply output power, if incoming voltage was sensed greater than 132 volts (AC) or less than 88 volts (AC). Simultaneous faults in the power supplies would result in the reactor feed pump tripping.

The speed control system power supplies ultimately receive power from the 2C and 2D Buses. These buses are provided with an automatically initiated, automatically executed, quick, dead bus transfer. The scheme is capable of quickly transferring each bus section and its loads from the normal source (unit auxiliary transformer) to the preferred source (startup auxiliary transformer) in the event of a loss of the normal power source or unit trip. This transfer results in the buses being disconnected from both voltage sources for a period of between one and five cycles, per the Updated Final Safety Analysis Report. As a result, the reactor feed pump speed control system power supplies would fault, and the reactor feed pumps would trip following unit trips and during certain voltage transients on the 2C and 2D Buses. The licensee's evaluation of the modification failed to recognize this vulnerability.

Performance Deficiency -The licensee performed an inadequate design review of the Unit 2 reactor feed pump speed control system modification (EC 46822). Specifically, the design review failed to recognize that the system's power supplies would fault and fail to provide power during supply voltage transients. Voltage transients of sufficient magnitude to fault the power supplies, resulting in tripping of the reactor feed pumps, was determined to occur following automatic transfer of emergency buses 2C and 2D from the Unit Auxiliary Transformer to the Startup Auxiliary Transformer following a reactor/turbine trip.

Exposure Time - The condition existed from Unit 2 startup on 4/6/03 until 12/7/03 when it was eliminated with a plant modification that altered the power sources for the pump controls. This is 245 days. Although the plant was shutdown for 4 days during this time period, the SDP evaluation is not based upon the actual condition of the plant or the equipment out of service during the exposure period.

Date of Occurrence - During the outage prior to the 4/6/03 startup.

II. Safety Impact: The deficiency results in the main feedwater system being unavailable for primary system makeup for all transients that result in a trip. Feedwater/condensate is usually credited about 70% of the time in the SPAR model.

III. Risk Analysis/Considerations

Assumptions

1. Any transient at power causing the generator to trip will also lead to a loss of main feedwater.

2. For events where the feedwater trips, but HPCI or RCIC initiates, MSIV isolation on low water level will not necessarily occur, and recovery of feedwater is possible, with a failure rate of .1. If HPCI and RCIC fails, feedwater is not recoverable, due to MSIV closure.

PRA Model used for basis of the risk analysis: Revision 3i SPAR, as modified 3/2004, backed up by licensee analysis.

IV. Calculations

The SPAR model, rev 3i, was used with several significant revisions. Revisions included:

1. The update for the NUREG 5496 loss of offsite power, recovery curves, and EDG mission time
2. Revisions to fault trees SDC, CSS, SPC-a, SPC-b to allow cross tie electrical power to these systems
3. Revised RSW-HXA,RHR-A-SS, and RHR-B-SS to allow credit for CSW/NSW cross tie
4. Revised CVS to remove the requirement for containment purge for containment sucess
5. Revised the failure probability of one SRV fails to close from 0.18 to .031 based on latest SPAR value
6. Revised the HPCI injection valve failure rate from 0.2 to 0.02 based on a discussion with INEEL
7. Revised fail to depressurize terms to represent mechanical failures of the ADS system.

SPAR was run for the case where the main feed pumps fail to run. The change in frequency on an annualized basis was 2.3E-5/year. Sequences Tran56-05,Tran 56-04,Tran 10, and SLOCA 13 concern the cases where HPCI or RCIC are available, so MSIV isolation is not expected, and feedwater should be recoverable. If the importance for these sequences is subtracted from the total, then 10% is added back in for the sequences in which recovery fails, the required adjustment should have been accomplished. When these contributions are subtracted from the delta:

8.2E-7 - .9[(cdp for sequences)-(ccdp for sequences)]=
8.2E-7 - .9*(5.4E-8+5.3E-8+1.9E-8+9.1E-9) = 8.2E-7 - 1.3E-7
6.9E-7/year

Delta CDF for Exposure Time

245 days had elapsed
6.9E-7/year * 245 / 365 = 4.6E-7/year

The contribution due to external events and fires is not considered to impact the calculation by much, since the delta is dominated by TRAN, which has a relatively high initiating event frequency. Any increase in frequency due to these other infrequently occurring contributors would have minimal impact. Most external weather or grid related initiators result in loss of feedwater anyway.

The utility's calculation results in a value of about 7E-7 for the condition's duration, which would roughly correspond to the SPAR result.

LERF - Brunswick has a concrete backing on its Drywell and wetwell liner. The assumptions of IMC0609, Appendix H do not apply. New LERF guidelines were developed for Brunswick's configuration, which reduce the LERF contribution for low and high pressure Non-ATWS sequences. The Non-ATWS contributions were reduced to a value where the CDF threshold dominates the LERF threshold. For risk, ATWS sequences are valued using the Appendix H assumptions. Sequences Tran58-09 are ATWS sequences. The LERF multiplier would be .3. 7E-8 * .3 = 2.1E-8 The other dominant sequence is a SLOCA sequence which would result in low pressure at vessel melt through, so its contribution would be negligible due to the concrete backing. LERF is GREEN.

V. Conclusions/Recommendations - Risk increase over the base case was < 1E-6. The issue is GREEN, primarily due to the duration, and the consideration that some trips resulting in a loss of feedwater are recoverable.