RAS 11673

May 17, 2006

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 04-832-02-OLA
(Vermont Yankee Nuclear Power Station)	)	(Operating License Amendment)

ENTERGY'S INITIAL STATEMENT OF POSITION ON NEW ENGLAND COALITION CONTENTION 3

Pursuant to 10 C.F.R. § 2.1207(a)(1) and the Atomic Safety and Licensing Board's ("Board") Revised Scheduling Order dated April 13, 2006 ("Revised Scheduling Order"), [1] Applicants Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (collectively "Entergy") hereby submit their Initial Statement of Position ("Statement") on New England Coalition Contention 3 ("NEC Contention 3"). This Statement is supported by the "Testimony of Craig J. Nichols and Jose L. Casillas on NEC Contention 3 – Large Transient Testing" ("Entergy Dir.") and exhibits thereto, being filed simultaneously herewith.

I. INTRODUCTION

One of the contentions originally proposed by NEC was Contention 3,[2] which asserts that Entergy's application for an extended power uprate ("EPU") for the Vermont Yankee Nuclear

[1] As directed by the Board, "[t]he initial written statement should be in the nature of a trial brief that provides a precise road map of the party's case, setting out affirmative arguments and applicable legal standards, identifying witnesses and evidence, and specifying the purpose of witnesses and evidence (i.e., stating with particularity how the witness or evidence supports a factual or legal position)." Revised Scheduling Order at 3.

[2] New England Coalition's Request For Hearing, Demonstration of Standing, Discussion of Scope of Proceeding and Contentions, dated August 30, 2004, at 11 ("NEC Hearing Request").

Template = SECY-037

SECY-02

Power Station ("VY") ("EPU Application") should not be approved unless performance of Large Transient Testing ("LTT") is a made a condition of the uprate.[3] The scope of NEC Contention 3 has been recently clarified by the Board, which has ruled that "the 'Large Transient Testing' at issue in NEC Contention 3, and the testimony and other evidence to be submitted concerning it, are limited to the main steam isolation valve closure test and the turbine generator load rejection test." Memorandum and Order (Clarifying the Scope of NEC Contention 3) (April 17, 2006), slip op. at 3.

NRC's Review Standard RS-001, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) refers to Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," ("SRP 14.2.1") for the testing related to extended power uprates.[4] Entergy Dir. at A18. SRP 14.2.1 in turn specifies that LTT is to be performed as part of the extended power uprate, and that the tests are to be performed in a similar manner to the testing that was performed during initial startup testing of the plant. Id. and Entergy Dir. Exhibit 4 at 14.2.1-5. The SRP also provides guidance on how to justify a request for deletion of testing requirements. Entergy Dir. at A19 and Entergy Dir. Exhibit 4 at 14.2.1-7 – 14.2.1-10.

The LTT that the SRP seeks to have performed for an EPU are the main steam isolation valve closure test and the generator load rejection test. Entergy Dir. at A17 and Entergy Dir. Exhibit 4 at 14.2.1-9. The main steam isolation valve ("MSIV") test is performed by rapidly closing all eight MSIVs from full rated power. Entergy Dir. at A20. Sudden closure of all MSIVs at power is an "Abnormal Operational Transient" as described in Chapter 14 of the VY Updated Final Safety Analysis Report ("UFSAR"). Id.

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[3] As admitted by the Board, NEC Contention 3 reads: "The license amendment should not be approved unless Large Transient Testing is a condition of the Extended Power Uprate." Memorandum and Order, LBP-04-28, 60 NRC 548, 580, Appendix 1 (2004).

[4] RS-001 is available in the ADAMS system under accession number ML033640024. The cited provision appears on Section 2.12.1 at 255.

A generator load rejection (also known as a "turbine generator load rejection") is initiated by a rapid closure of the turbine control valves after a load rejection. Entergy Dir. at A23. A generator load rejection is an Abnormal Operational Transient as described in Chapter 14 of the UFSAR. Id.

In its EPU Application, Entergy sought an exception to performing LTT as part of the testing program for the EPU. Entergy Dir. at A10; see also Entergy Dir. Exhibits 5 and 6. In seeking that exception, Entergy addressed the factors outlined in SRP 14.2.1 as justifying not performing the LTT, including: (1) VY's general response to unplanned transients;(2) analyses of specific events; (3) the impact of EPU modifications; and (4) relevant industry experience. Entergy Dir. at A26.

In its Final Safety Evaluation Report for the VY EPU, the NRC Staff agreed that the exception from LTT requested by Entergy should be granted. Entergy Dir. at A28 and Entergy Dir. Exhibit 7 (Final SER) at 267-271.[5] The Staff reached the following conclusion:

> Based on its review of the information provided by the licensee, as described above, the NRC staff concludes that in justifying test eliminations or deviations, other than the condensate and feedwater system testing discussed in SE Section 2.5.4.4, the licensee adequately addressed factors which included previous industry operating experience at recently uprated BWRs, plant response to actual turbine and generator trip tests at other plants, and experience gained from actual plant transients experienced in 1991 at the VYNPS. From the EPU experience referenced by the licensee, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about transient modeling or actual plant response. As such, the staff concludes that there is reasonable assurance that the VYNPS SSCs will perform satisfactorily in service under EPU conditions. The staff also noted that the

[5] The SER is available in ADAMS under accession number ML060050028. Pages 267-271 are included as Entergy Dir. Exhibit 7.

> licensee followed the NRC staff approved GE topical report guidance which was developed for the VYNPS licensing application.

Final SER at 271.

Likewise, in its letter to the NRC Chairman following its review of the EPU Application, the Advisory Committee on Reactor Safeguards concluded:

> 3. Load rejection and main steam isolation valve closure transient tests are not warranted. The planned transient testing program adequately addresses the performance of the modified systems.

Letter from Graham B. Wallis to NRC Chairman Nils Diaz dated January 4, 2006 Entergy Dir., Exhibit 22.

II. APPLICABLE LEGAL STANDARDS

In propounding NEC Contention 3, NEC did not specify what legal standards would be contravened by the granting of the exception from LTT at VY, nor was the issue addressed in the Board's discussion of the issue when the contention was admitted. See NEC Heating Request at 11; LBP-04-28, 60 NRC at 571-72. Section 2.12 of the SER for the VY EPU, on the other hand, states that the acceptance criteria for the VY EPU test program "are based on 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs [structures, systems and components] will perform satisfactorily in service." SER at 261. Criterion XI of Appendix B to 10 C.F.R. Part 50 states:

> XI. Test Control
>
> A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test program shall include, as appropriate, proof tests prior to installation, preoperational tests, and operational tests during nuclear power plant or fuel reprocessing plant operation, of structures, systems, and components. Test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and

> that the test is performed under suitable environmental conditions. Test results shall be documented and evaluated to assure that test requirements have been satisfied.

10 C.F.R. 50, Appendix B, Criterion XI.

Entergy agrees that the legal standard for determining whether the EPU should be approved without the performance of LTT is whether, in the absence of LTT, the test program implemented by Entergy for the EPU complies with Criterion XI by demonstrating that structures, systems, and components will perform satisfactorily in service at the proposed EPU power level.

III. APPLICANTS' STATEMENT OF POSITION ON FACTUAL ISSUES

A. Entergy's witnesses and evidence

Entergy's testimony on NEC Contention 3 will be presented by a panel of two experts, each with extensive experience in boiling water reactor ("BWR") operation and the response of BWRs like VY to large transients. The first of Entergy's witnesses, Mr. Craig J. Nichols, is the EPU Project Manager for VY and, in that capacity, he is the manager for the implementation of EPU at VY. Entergy Dir. at A2. As manager for the VY EPU project, Mr. Nichols has been responsible for overseeing the plant modifications needed to implement the upgrade and the performance of the technical evaluations and analyses required to demonstrate VY's ability to operate safely under uprate conditions. Id. and Entergy Dir. Exhibit 1. With twenty years of work experience at VY, Mr. Nichols is familiar with VY's operating history, current plant operations, and the anticipated operating conditions after the uprate. Entergy Dir. at A3 and A5.

The other witness in Entergy's panel is Mr. Jose L. Casillas, the Plant Performance Consulting Engineer in the Nuclear Analysis group of the Engineering organization of General Electric ("GE") Nuclear Energy. Mr. Casillas is responsible for BWR plant performance design and analyses, including evaluations in support of EPU applications. Entergy Dir. at A7. He has over thirty-three years of direct technical experience working in all aspects of plant performance at GE Nuclear Energy, including transient analysis. He is familiar with the analytical codes used to predict BWR plant response to operational transients and with the industry experience regarding the response of BWRs to large transients. Id. at A7 - A9 and Entergy Dir. Exhibit 2.

The testimony and opinions of the Entergy witnesses on NEC Contention 3 are based on both their technical expertise and experience and their first hand knowledge of the issues raised in NEC Contention 3. By contrast, NEC's witness on this contention, Dr. Joram Hopenfeld, has provided no indication that he has any experience or expertise in the analysis or evaluation of large operational transients at BWRs, nor does he profess to have any familiarity with the operational experience at either VY or other comparable plants with large transients. See "Curriculum Vitae for Dr. Joram (Joe) Hopenfeld," Exhibit A to NEC's Answer to Entergy's Motion for Summary Disposition of New England Coalition Contention 3 (Dec. 22, 2005).

The evidence provided by the Entergy witnesses demonstrates that there is no support for the claims made in NEC Contention 3. The extensive and conservative engineering analyses, historical test and actual transient data, individual component testing, and observed performance at other plants experiencing large transients provide reasonable assurance and confidence that VY systems will function as designed in mitigation of large transients from EPU conditions. The potential benefits, if any, from LTT at VY are significantly outweighed by the adverse effect on plant systems and components from the tests themselves. VY's request for an exception to LTT, therefore, is reasonable and poses no threat to public health and safety. Entergy Dir. at A61.

B. The analytical tools used by Entergy provide transient response predictions that bound plant performance in large transient events under EPU conditions

1. In advance of implementation of the EPU, GE performed analyses of the performance of VY under EPU conditions. These analyses included, among others, the results of licensing basis large transient simulations conducted using GE's ODYN code. Entergy Dir. at A40 and Entergy Dir. Exhibit 8.

2. The results of these simulations verified that: (1) these transients remain the limiting transients from the perspective of the selected parameters, and (2) the results remain within the design and license limits, and show significant margin to the limits. Id.
3. The large transient analyses for VY predict the behavior of the safety- and non-safety-related systems in the plant during operational transients. These large transient analyses model both the performance of the secondary side of the plant and any relevant potential interactions between primary and secondary systems in a transient to evaluate the parameters of interest. Id. at A29.
4. ODYN is a proprietary code developed by GE and approved by the NRC in 1981 for use in the analysis of GE BWR plant response to pressurization transients. A description of the ODYN model and the qualification as well as the NRC Safety Evaluation Report can be found in NEDO 24154-A (proprietary) dated August 1986. The ODYN model has been upgraded over the last 20 years to include greater modeling detail such as increased nodes, advanced physics correlations, and more representative control systems. These changes have consistently improved the accuracy of the ODYN code and reduced the uncertainty in its predictions compared against the qualification tests. Recently, the ODYN model has been approved by the NRC for application to all GE BWR plant transients. Id. at A30.
5. The ODYN code models BWR vessel physical components, mechanical equipment functions, control systems and nuclear/thermal-hydraulic phenomena. The simulation involves describing the physical plant in the model (i.e., volumes, flow paths, resistances), establishing the desired operating conditions (i.e., water level, power, pressure) and introducing a disturbance (i.e., valve closure, pump trip, control action). The ODYN model predicts the plant response behavior based on its physical model correlations. The ODYN code has

been assessed against actual MSIV closure transients and load rejection transients at an operating facility. Id. at A31.

6. The ODYN analyses assume operational configurations and component/system failures that bound (i.e., represent more severe conditions than) the transients that would occur during normal plant operations or design basis events, including large transients. Id.
7. The ODYN code is accepted as a best estimate code, though it includes some conservative biases due to simplified aspects of the model. GE has qualified the ODYN code against all significant plant transients and the NRC has accepted that the ODYN code is a dependable best estimate code. Id. at A34. As a best estimate code benchmarked against all significant transients, ODYN is capable of predicting accurately the plant behavior during transients occurring at higher EPU power levels. Id. at A35.
8. The ODYN code has been benchmarked against all significant plant transients including turbine trip (equivalent in its effects to a generator load rejection test) and MSIV closure events. Id. at 36. The turbine trip data were obtained from the Peach Bottom and KKM – Muhlenberg plants; the MSIV closure data were obtained from the Hatch plant. Id. at A37.
9. The results of ODYN's benchmark assessments demonstrate the ability of the code to accurately predict plant performance during large transients. All versions of the ODYN code have been assessed against the benchmark tests and continue to form the basis for the code's accuracy. The current version of the ODYN code continues to accurately predict the overpower magnitude and slightly overpredict the overpressure magnitude. Id.
10. It is reasonable to conclude that the ODYN simulations of VY's behavior in large transients during EPU operation accurately predicts the actual plant response to those transients because the ODYN model is qualified for the analysis of this type of transient and

the resulting parameters are within the applicable physical correlations of the model for the bounding licensing analysis. Also, a VY LTT at the increased power condition at constant pressure would be significantly milder than the ODYN analyses. Several plant transients have been compared against ODYN predictions over the years to assess the specific BWR licensing basis. All of these comparisons have determined that the licensing predictions are bounding and that the plant equipment response is consistent with its design basis. Id. at A41.

C. The behavior of BWRs that have undergone EPUs under large transients has been satisfactory and within the bounds of analytical predictions, thus confirming the validity of the transient analysis methodology

11. The VY EPU was implemented following the guidelines contained in the NRC-approved document "General Electric Company Licensing Topical Report (CLTR) for Constant Pressure Power Uprate Safety Analysis: NEDC-33004P-A Rev. 4, July 2003" ("NEDC-33004P-A"). Implementation of the guidance in NEDC-33004P-A results in an increase in reactor power without an increase in reactor operating pressure (i.e., a "constant pressure power uprate" or "CPPU"). Id. at A13.

12. Thirteen BWRs similar to VY have implemented EPUs without increasing reactor operating pressure, including eleven plants in the United States and two in Switzerland (KKL – Leibstadt and KKM – Muhlenberg). Id. at A15. None of the eleven domestic BWR plants similar to VY that have implemented EPUs without increasing reactor operating pressure has been required to perform LTT at EPU power levels. Id.

13. Those thirteen plants are similar to VY in all significant respects that bear on large transient performance. Id. at A16. For example, the Brunswick units are both BWR/4 plants with Mark 1 containments, like VY. Comparison of the designs of important parameters

for the Brunswick and VY plants shows their striking similarities in areas such as power density, steam relief and bypass capacities that would affect the large transient performance of the plants. Such similarity supports the prediction that the performance of both plants in the event of a large transient would be substantially the same. Id. and Entergy Dir. Exhibit 3.

14. Of the thirteen BWR plants that have implemented EPUs without increased reactor operating pressure, four (Hatch 1 and 2, Brunswick 2, and Dresden 3) have experienced one or more unplanned large transients from uprated power levels. Entergy Dir. at A44 and Entergy Dir. Exhibits 9-16.

15. Hatch Unit 2, which like VY has a BWR/4 Mark I reactor, experienced a post-EPU unplanned event that resulted in a generator load rejection from approximately 111% original rated thermal power ("OLTP") (98% of uprated power) in May 1999. All systems at Hatch Unit 2 functioned as expected and no anomalies were seen in the plant's response to this event. Entergy Dir. at A44 and Entergy Dir. Exhibit 9.

16. Hatch 2 also experienced a post-EPU reactor trip on high reactor pressure as a result of MSIV closure (from 113% OLTP (100% of uprated power)) in 2001. All systems functioned as expected and designed, given the conditions experienced during the event. Entergy Dir. at A44 and Entergy Dir. Exhibit 10.

17. Hatch Unit 1, which like VY has a BWR/4 Mark I containment, has experienced two post-EPU turbine trips from 112.6% and 113% of OLTP (99.7% and 100% of uprated power). Again, the behavior of the primary safety systems was as expected. No new plant behaviors for either plant were observed. Entergy Dir. at A44 and Entergy Dir. Exhibits 11 and 12.

18. The performance of the Hatch units during transients was bounded by the ODYN code predictions for those units. Entergy Dir. at A44.

19. The Hatch operating experience shows that the analytical models being used at VY are capable of modeling plant behavior at EPU conditions. Id.

20. Progress Energy's Brunswick Unit 2, which is a BWR/4 with a Mark I containment very similar to VY, experienced a post-EPU unplanned event that resulted in a generator/turbine trip due to loss of generator excitation from 115.2% OLTP (96% of uprated thermal power) in the fall of 2003. No anomalies were experienced in the plant's response to this event, and no unanticipated plant behavior was observed. Entergy Dir. at A44 and Entergy Dir. Exhibit 13.

21. The Brunswick Unit 2 operational experience shows that the analytical models being used at Brunswick (which are the same as those used at VY) are capable of modeling primary and secondary plant behavior at EPU conditions. Entergy Dir. at A44.

22. Exelon Generating Company LLC's Dresden Unit 3, like VY a BWR/4 with a Mark I containment, experienced in January 2004 two turbine trips from 112.3% and 113.5% of OLTP (96% and 97% of uprated power). The plant response was as predicted in the transient analyses, which use the same methodology as those performed at VY. Entergy Dir. at A44 and Entergy Dir. Exhibits 14 and 15.

23. In May 2004, Dresden 3 also experienced a loss of offsite power which resulted in a turbine trip on Generator Load Rejection from 117% of OLTP (100% of uprated power). The plant response was again as predicted in the transient analyses. Entergy Dir. at A44 and Entergy Dir. Exhibit 16.

24. The Dresden 3 response to these transients indicates that the analytical models used for transient analyses (which are the same as those used at VY) are capable of accurately predicting transient plant behavior at EPU conditions. Entergy Dir. at A44.

25. In all cases, the plants experienced no anomalous response to large transients from EPU operating levels and the plant response was as predicted in the transient analyses, which use the same methodology as those performed at VY. Id.

26. In every instance in which unplanned large transients from EPU power levels were experienced at these plants and an analysis of the scenario involved in the transients existed, the plant's response was bounded by the analyses performed using ODYN and no new phenomena were exhibited in the response. Id. at A45.

27. The response of these plants to operational transients indicates that the analytical models used for transient analyses are capable of accurately predicting transient plant behavior at EPU conditions and supports the conclusion that VY should also respond as predicted to large transients during EPU operation. Id. at A44.

D. Industry experience with Large Transient Testing Confirms the Analytical Predictions

28. LTT has been performed after an EPU at one plant similar to VY. The KKL (Leibstadt) power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 104.2% OLTP to 119.7% OLTP. Uprate testing was performed at 110.4% OLTP in 1998, 113.4% OLTP in 1999, 116.7% OLTP in 2000 and 119.7% OLTP in 2002. KKL testing for major transients involved turbine trips at 113.4% OLTP and 116.7% OLTP, and a generator load rejection test at 104.2% OLTP. Id. at A46.

29. The transient tests at KKL showed that the uprate analyses performed by KKL (which were performed using the ODYN code, as were VY's) consistently reflected the behavior of the plant. Id.

30. A comparison of the KKL turbine test transient performance against the ODYN predictions shows consistency between the test results and those predicted in the model's qualification, as well as in other comparisons between ODYN runs and plant operating data. In all cases, the ODYN model slightly overpredicts vessel peak pressure. Id. at A47.

31. The KKL turbine trip test is an excellent prediction of what a test at VY would show because KKL has a 2% higher power density than VY and both plants are of a full turbine bypass capacity design. Id.

32. The fact that the Hatch, Brunswick and Dresden plants, all of which are similar in design to VY, experienced no anomalous response to large transients from EPU operating levels supports the conclusion that VY should also respond as predicted to large transients during EPU operation. Id. at A44.

E. The VY Operational Experience Justifies the LTT Exception

33. Between 1991 and 2005, VY experienced five large transient while operating at full pre-EPU power levels. Id. at A49 and Entergy Dir. Exhibits 17-21.

34. No significant anomalies were seen in the plant's response to those five events. The performance of VY in the transients it experienced at pre-EPU power levels was well within the bounds of the ODYN analyses. Entergy Dir. at A50.

35. VY's historical response to large transients provides a basis for an exception to LTT. In particular, the transients in 2004 and 2005 occurred after most of the modifications associated with EPU were already implemented, including the new HP turbine rotor, Main Gen-

erator Stator rewind, the new high pressure feedwater heaters, condenser tube staking, an upgraded isophase bus duct cooling system, and condensate demineralizer filtered bypass. In each instance, the modified or added equipment functioned normally during the transient. The plant's performance during these recent transients, including that of the modified components, demonstrates that the EPU modifications do not significantly affect the plant's response during transient conditions. Id. at A51.

F. System and component testing during normal operations provide a basis for an exception to LTT

36. Technical Specification-required surveillance testing (e.g., component testing, trip logic system testing, simulated actuation testing) is routinely performed during plant operations. Such testing demonstrates that the structures, systems and components ("SSCs") required for appropriate transient performance will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis. Id. at A52.

37. The main components involved in LTT are tested frequently. The MSIVs are tested quarterly. The safety relief valves and spring safety valves are tested once every operating cycle. These valves are required to perform in accordance with the design during large transients; their periodic testing assures that their performance during large transients will be acceptable. Likewise, the reactor protection system instrumentation that is relied on to mitigate large transients is tested quarterly, assuring that it will carry out its design function in the event of a large transient. Id. at A53.

38. Because the characteristics and functions of SSCs are tested periodically during plant operations, they do not need to be demonstrated further in a large transient test. In addition, limiting transient analyses (i.e., those that affect core operating and safety limits) are re-

performed for each operating cycle and are included as part of the reload licensing analysis. Id. at A54.

G. Similarities in pre- and post-EPU plant design and physical configuration suggest that EPU implementation should have no effect on the plant's response to large transients

39. There are great similarities in design and system function between the pre- and the post-EPU VY plant configuration Id. at A55. While some operating parameters (e.g., core power distribution) have been modified to accommodate EPU operation and some setpoint changes were made, these changes do not measurably contribute to response to large transient s. None of the modifications that have been made will introduce new thermal-hydraulic phenomena as a result of power uprate, nor are any new system interactions during or as the result of analyzed transients introduced. No systems have been added or changed at VY that are required to mitigate the consequences of the large transients that would be the subject of the LTT. Id.

40. Operationally, the EPU modifications have no significant effect on plant transient analysis because, since the uprate is a constant pressure uprate, most of the plant's systems will operate in the same manner as before the uprate. Also, the VY EPU is performed without a change in operating reactor dome pressure from current plant operation. Id.

41. There have been no major equipment modifications or new hardware installations at VY that could result in different large transient performance than that predicted by the analyses and the plant's prior operating history. Id. at 56. Most of the EPU modifications were made to non-safety related components, which are not credited in licensing basis transient analyses. Incidental modifications associated with EPU, such as alarms, indications, and scaling changes also do not impact transient response. Id. at A56.

42. Not only are the number of equipment modifications and additions relatively small but none of these modifications will introduce any new thermal-hydraulic phenomena as a result of the power uprate. Nor are any new system interactions during or as the result of analyzed transients introduced. Id. at A57.

43. VY's performance during the 2004 and 2005 transients, which occurred after most of the modifications associated with EPU were already implemented, demonstrates that the EPU modifications do not significantly affect the plant's response during transient conditions. Id. at A51.

H. LTT would have an adverse impact on VY without compensating safety benefits

44. The performance of a SCRAM from high power, such as those that take place during LTT, results in an undesirable transient cycle on the primary system. The occurrence of primary system transient cycles should be minimized, since they introduce unnecessary stresses on the primary system components. Id. at A58.

45. An MSIV closure test performed as part of LTT would not result in an appreciable transient because the SCRAM signals would issue from the MSIV position switches and a SCRAM would immediately take place. Id. at A22.

46. A generator load rejection test performed as part of LTT would result in bypass valve opening and would in effect be the same as any plant trip at full power and thus provide no comparable information to that resulting from an actual GLRWB transient. Id. at A25.

47. If performed, the MSIV closure and generator load rejection tests would not confirm any new or significant aspect of performance that is not routinely demonstrated by component level testing and demonstrated through analyses. Id. at A27.

48. The undesirable effects of performing the tests outweigh the benefits of any limited additional information that may be gained from them. Id. at A58.

49. In addition, performance of each LTT causes a plant shutdown. Any plant shutdown results in a generation outage for a period of time (typically 2-3 days) for the plant. Since there are no measurable safety benefits to be derived from the performance of the tests, the loss of generation revenue and other costs associated with the performance of the tests cannot be economically justified. Id.

IV. CONCLUSION

The extensive and conservative engineering analyses, historical test and actual transient data, individual component testing, and observed performance at other plants experiencing large transients provide reasonable assurance and confidence that VY systems will function as designed in mitigation of large transients from EPU conditions. The potential benefits, if any, from LTT at VY are significantly outweighed by the adverse effect on plant systems and components from the tests themselves. VY's request for an exception to LTT, therefore, is reasonable and poses no threat to public health and safety. Id. at A61.

Consequently, the test program implemented by Entergy for the EPU, which excludes the performance of LTT, complies with Criterion XI of Appendix B to 10 C.F.R. Part 50 by demonstrating that structures, systems, and components will perform satisfactorily in service at the proposed EPU power level.

Respectfully submitted,

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Dated: May 17, 2006

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NUCLEAR REGULATORY COMMISSION

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ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)
(Vermont Yankee Nuclear Power Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of "Entergy's Initial Statement of Position on New England Coalition Contention 3," Testimony of Craig J. Nichols and Jose L. Casillas On NEC Contention 3 – Large Transient Testing," "Affidavit of Craig J. Nichols," and "Affidavit of Jose L. Casillas" were served on the persons listed below by deposit in the U.S. mail, first class, postage prepaid, and where indicated by an asterisk by electronic mail, this 17th day of May, 2006.

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Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC. (Vermont Yankee Nuclear Power Station)	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)

TESTIMONY OF CRAIG J. NICHOLS AND JOSE L. CASILLAS ON NEC CONTENTION 3 – LARGE TRANSIENT TESTING

May 17, 2006

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

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I. WITNESS BACKGROUND

Craig J. Nichols ("CJN")

Q1. Please state your full name.

A1. (CJN) My name is Craig J. Nichols.

Q2. By whom are you employed and what is your position?

A2. (CJN) I am the Extended Power Uprate Project Manager for Entergy Nuclear Operations, Inc. ("Entergy"). In that capacity, I am the manager for the implementation of the extended power uprate ("EPU") at the Vermont Yankee Nuclear Power Station ("VY").

Q3. Please summarize your educational and professional qualifications.

A3. (CJN) My professional and educational experience is summarized in the *curriculum vitae* attached to this testimony as Exhibit 1. Briefly summarized, I have over twenty years of professional experience working in various technical and managerial capacities at

VY. For the last four years, I have managed all activities relating to the implementation of the EPU at VY. I received a B.S. Degree in Electrical Engineering from Northeastern University.

Q4. What is the purpose of your testimony?

A4. (CJN) The purpose of my testimony is to address, on behalf of Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (collectively "Entergy"), Contention 3 submitted by the New England Coalition ("NEC") in this proceeding. As admitted by the Atomic Safety and Licensing Board ("Board"), NEC Contention 3 reads:

> The license amendment should not be approved unless Large Transient Testing is a condition of the Extended Power Uprate.

Memorandum and Order, LBP-04-28, 60 NRC 548, 580, App. 1 (Nov. 22, 2004).

In addition, the scope of NEC Contention 3 has been clarified recently by the Board, which has ruled that "the 'Large Transient Testing' at issue in NEC Contention 3, and the testimony and other evidence to be submitted concerning it, are limited to the main steam isolation valve closure test and the turbine generator load rejection test." Memorandum and Order (Clarifying the Scope of NEC Contention 3) (April 17, 2006), slip op. at 3.

Q5. What has been your role in the VY EPU project as it relates to NEC Contention 3?

A5. (CJN) In my capacity as manager for the VY EPU project, I have been responsible for overseeing the plant modifications needed to implement the upgrade and the performance of the technical evaluations and analyses required to demonstrate VY's ability to operate safely under uprate conditions. I am familiar with VY's operating history, current plant operations, and the anticipated operating conditions after the uprate.

Jose L. Casillas ("JLC")

Q6. Please state your full name.

A6. (JLC) My name is Jose L. Casillas.

Q7. By whom are you employed and what is your position?

A7. (JLC) I am the Plant Performance Consulting Engineer in the Nuclear Analysis group of the Engineering organization of General Electric ("GE") Nuclear Energy. In that capacity, I am responsible for boiling water reactor ("BWR") plant performance design and analyses, including evaluations in support of EPU applications and the development and application of computer codes used to predict BWR plant performance.

Q8. Please summarize your educational and professional qualifications.

A8. (JLC) My professional and educational experience is summarized in the *curriculum vitae* attached to this testimony as Exhibit 2. Briefly summarized, I have over thirty-two years of direct technical experience working in all aspects of plant performance at GE Nuclear Energy, including transient analysis. I received a B.S. Degree in Mechanical Engineering from the University of California, Davis.

Q9. What is the purpose of your testimony?

A9. (JLC) The purpose of my testimony is to address those aspects of NEC Contention 3 that relate to the industry experience regarding the response of BWRs to large transients.

II. OVERVIEW

A. Issues Raised By Contention

Q10. What is your understanding of the technical issues raised by NEC Contention 3?

A10. (CJN) In its license amendment application ("EPU Application") to increase the authorized power level of VY from 1593 megawatts thermal ("MWt") to 1912 MWt, Entergy sought, in accordance with the guidance in Standard Review Plan ("SRP") 14.2.1, to be excused from performing Large Transient Testing ("LTT"). NEC Contention 3 asserts that LTT must be conducted to assure that the public health and safety is protected during EPU operations, and that the EPU should not be approved unless LTT is required to be performed.

Q11. Do you agree with the assertion in NEC Contention 3 that the EPU Application should not be approved unless LTT is a condition to the approval of the license amendment?

A11. (CJN, JLC) No.

Q12. What is the basis for your disagreement?

A12. (CJN, JLC) The effects of large transients at EPU conditions can be predicted analytically, on a plant-specific basis, without the need for actual transient testing. This conclusion is supported by: (a) the similarity of the pre-EPU and post-EPU VY design configuration and system functions; (b) results of past transient testing at VY and other BWRs and the plants' responses to unplanned transients; (c) confirmation that the transient safety analysis results bound the experience from actual transients; and (d) the experience with unplanned transients at other post-EPU plants.

The transient analyses performed for the VY EPU demonstrate that all safety criteria are met under uprate operating conditions. On the other hand, a reactor SCRAM from EPU power levels –

such as would occur during LTT – would provide no meaningful new information and would cause an undesirable transient cycle on the station's systems.

III. DISCUSSION

A. EPU General Description

Q13. Please describe the analytical bases for the VY EPU Application.

A13. (CJN) The VY EPU request was prepared following the guidelines contained in the NRC-approved document "General Electric Company Licensing Topical Report (CLTR) for Constant Pressure Power Uprate Safety Analysis: NEDC-33004P-A Rev. 4, July 2003" ("NEDC-33004P-A"). Implementation of the guidance in NEDC-33004P-A results in an increase in reactor power without an increase in reactor operating pressure (i.e., a "constant pressure power uprate" or "CPPU").

Q14. Why is a CPPU advantageous?

A14. (JLC) The CPPU methodology, which maintains the same reactor operating pressure as originally licensed, greatly simplifies the engineering analyses and equipment and procedural changes required to achieve uprated conditions. It also assures that the plant's performance during transients will be analogous to that before the uprate.

Q15. Have any other plants uprated their thermal power using the CPPU approach?

A15. (JLC) Yes. Thirteen BWRs similar to VY have implemented EPUs without increasing reactor operating pressure:

- Hatch Units 1 and 2 (1998) (105% to 113% of Original Licensed Thermal Power ("OLTP")) (The Hatch units previously had 5% "stretch" uprates, from 100% to 105% OLTP)
- Monticello (1998) (106% OLTP)

- Muehleberg (i.e., KKM) (1993) (105% to 116% OLTP)
- Leibstadt (i.e., KKL) (2000) (104% to 119.7% OLTP)
- Duane Arnold (2001) (104.1% to 119.4% OLTP) (The Duane Arnold unit previously had a 4.1% "stretch" uprate, from 100% to 104.1% OLTP)
- Dresden Units 2 and 3 (2001) (100% to 117% OLTP)
- Quad Cities Units 1 and 2 (2001) (100% to 117.8% OLTP)
- Clinton (2002) (100% to 120% OLTP)
- Brunswick Units 1 and 2 (2002) (105% to 120% OLTP) (The Brunswick units previously had 5% "stretch" uprates, from 100% to 105% OLTP).

None of the domestic BWR plants similar to VY that have implemented EPUs without increasing reactor operating pressure has been required to perform LTT at EPU power levels.

Q16. How similar are these plants to VY?

A16. (JLC) They are similar to VY in all significant respects that bear on large transient performance. For example, the Brunswick units are both BWR/4 plants with Mark 1 containments, like VY. Comparison of the designs of important parameters for the Brunswick and VY plants shows their striking similarities in areas such as power density, steam relief and bypass capacities that would affect the large transient performance of the plants. This information has been extracted from UFSAR Tables 1.7.1 through 1.7.4 of the VY and Brunswick plants (attached as Exhibit 3) and supports the prediction that the performance of both plants in the event of a large transient would be substantially the same.

Parameter	VY	Brunswick	Comment
Power Density, MW/assembly	5.2	5.2	Equivalent
Number of Fuel Assemblies	368	560	VY has 34% less fuel and correspondingly lower steam flow than Brunswick.
Steam Line Length, ft.	331	391	VY has 15% smaller length, though the stem flow is correspondingly less than Brunswick.
Safety and Relief Capacity, % of Steam	60	56	Equivalent
Bypass capacity, % of Steam	86	69	VY has 25% greater capacity resulting in milder pressure rise following a turbine/generator trip.
Turbine Valve Closure Time, sec.	</= 0.1	</= 0.1	Equivalent
Main Steam Valve Closure Time, sec.	</= 5.0	</= 5.0	Equivalent
SCRAM Insertion Time, sec.	</= 3.5	</= 3.5	Equivalent

B. Large Transient Testing

Q17. Which are the tests that are classified as LTTs?

A17. (JLC) NEDC-33004P-A defines two LTTs applicable to EPU operations: the Main Steam Isolation Valve ("MSIV") Closure and the Generator Load Rejection tests. These tests, when conducted during plant operation, are similar to counterpart tests performed during initial plant startup testing. The NRC Staff has accepted these two LTTs as verifying that plant performance after EPU will be as predicted. See Exhibit 4, SRP 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs" (Draft, 2002) ("SRP 14.2.1"), Section III.C.2.f.

Q18. Does NRC guidance call for the performance of LTT at plants undergoing an EPU?

A18. (JLC) NRC's Review Standard RS-001, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) refers to SRP 14.2.1 for the testing related to extended power uprates. The SRP specifies that LTT is to be performed in a similar manner to the testing that was performed during initial startup testing of the plant. SRP 14.2.1, Section III.A.1.

Q19. Does the SRP make provisions for licensees to take exception to the performance of the LTT?

A19. (CJN) Yes. The SRP provides guidance on how to justify a request for elimination of the LTT requirement. Id., Section III.C.2. Entergy has followed the SRP guidance in taking exception to performing the large transient tests (i.e., MSIV closure and generator load rejection tests) during EPU operations at VY.

Q20. Please describe the MSIV closure transient.

A20. (CJN) Sudden closure of all MSIVs at power is an "Abnormal Operational Transient" as described in Chapter 14 of the VY Updated Final Safety Analysis Report ("UFSAR"). The MSIV closure test requires the fast closure (within 3.0 to 5.0 seconds) of all eight MSIVs from full rated power.

Q21. What is the purpose of the MSIV closure test?

A21. (CJN) The MSIV closure test is intended to (1) demonstrate that reactor transient behavior during and following simultaneous full closure of all MSIVs is as expected; (2) check the MSIVs for proper operation; and (3) determine or confirm MSIV closure time at full power.

Q22. What limiting aspect of plant operations is challenged during a Main Steam Isolation Valve closure transient?

A22. (CJN) The transient produced by an MSIV closure ("with Flux SCRAM") is the most severe abnormal operational transient from the standpoint of increase in nuclear system pressure. However, for the full licensing basis transient to take place it is necessary that the direct SCRAM signals from the valve position switches that would cause a reactor trip do not occur and that the SCRAM be delayed until the high flux signal is received. For that reason, an MSIV closure test performed as part of LTT would not result in an appreciable transient because the SCRAM signals would issue from the MSIV position switches and cause a SCRAM. The prompt SCRAM would significantly reduce the pressure transient that would otherwise occur.

Q23. Please describe a generator load rejection transient.

A23. (CJN) A Generator Load Rejection From High Power Without Bypass ("GLRWB") (commonly referred to as a "turbine generator load rejection" or a "generator load rejection") is an Abnormal Operational Transient as described in Chapter 14 of the UFSAR. The GLRWB transient is initiated by a rapid closure of the turbine control valves after a load rejection. For the full licensing basis transient to take place, however, it is necessary that all bypass valves fail to open. (The bypass valves open following a control valve closure to provide a path for steam to the condenser for plant cooldown and to maintain reactor pressure control.)

Q24. What aspect of plant operations is challenged in a GLRWB transient?

A24. (CJN) A GLRWB provides a bounding challenge to the fuel thermal limits, assuming none of the bypass valves open.

Q25. What is the purpose of a generator load rejection test?

A25. (CJN) The purpose of this test is to determine and demonstrate reactor response to a generator trip, with particular attention to the rates of change and peak values of power level, reactor steam pressure and turbine speed. In reality, however, a generator load rejection test performed as part of LTT would result in bypass valve opening and would in effect be the same as any plant trip at full power and thus provide no comparable information to that resulting from an actual GLRWB transient.

Q26. How did Entergy document its request for an exception to the LTT provisions in SRP 14.2.1?

A26. (CJN) Entergy included with its EPU Application as Attachment 7, "Justification for Exception to Large Transient Testing," Exhibit 5 hereto. Entergy subsequently supplemented its justification for the requested exception by submitting additional information. EPU Application, Supplement 3, Att. 2 (Oct. 28, 2003), attached as Exhibit 6. In those submittals, Entergy addressed the factors outlined in SRP 14.2.1 as justifying not performing the LTT, including: (1) VY's general response to unplanned transients; (2) analyses of specific transients; (3) the impact of EPU modifications; and (4) relevant industry experience. Entergy addressed the justification for not performing LTT in subsequent licensing submittals, including EPU Application Supplements 19 (October 2004) and 32 (September 2005).

Q27. Why did VY take exception to performing these LTTs for its EPU?

A27. (CJN) If performed, the MSIV closure and generator load rejection tests would not confirm any new or significant aspect of performance that is not routinely demonstrated by component level testing and demonstrated through analyses. It is important to note that the EPU transient analyses for VY were performed assuming operational configurations and component/system failures that are impractical to replicate during a testing program and are unlikely to be seen during actual plant operations, and therefore bound (i.e., represent more severe conditions than) the transients that would occur during actual plant operations or during LTTs.

Q28. Has Entergy's request for an exception from LTT been approved by the NRC Staff?

A28. Yes. In its Final Safety Evaluation Report for the VY EPU, the NRC Staff agreed that the exception from LTT requested by Entergy should be granted. SER at 267-270, attached as Exhibit 7. The Staff reached the following conclusion:

> Based on its review of the information provided by the licensee, as described above, the NRC staff concludes that in justifying test eliminations or deviations, other than the condensate and feedwater system testing discussed in SE Section 2.5.4.4, the licensee adequately addressed factors which included previous industry operating experience at recently uprated BWRs, plant response to actual turbine and generator trip tests at other plants, and experience gained from actual plant transients experienced in 1991 at the VYNPS. From the EPU experience referenced by the licensee, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about

transient modeling or actual plant response. As such, the staff concludes that there is reasonable assurance that the VYNPS SSCs will perform satisfactorily in service under EPU conditions. The staff also noted that the licensee followed the NRC staff approved GE topical report guidance which was developed for the VYNPS licensing application.

Q29. Can the behavior of the VY plant during a large transient be bounded analytically?

A29. (CJN) Yes. The large transient analyses for VY, which were performed using the NRC-approved code ODYN, predict the behavior of the safety- and non-safety-related systems in the plant during operational transients. These large transient analyses model both the performance of the secondary side of the plant and any relevant potential interactions between primary and secondary systems in a transient to evaluate the parameters of interest.

Q30. Please provide a summary description of the ODYN code.

A30. (JLC) ODYN is a proprietary code developed by GE and approved by the NRC in 1981 for use in the analysis of GE BWR plant response to pressurization transients. A description of the ODYN model and the qualification as well as the USNRC Safety Evaluation Report can be found in NEDO 24154-A (proprietary) dated August 1986. The ODYN model has been upgraded over the last 20 years to include greater modeling detail such as increased nodes, advanced physics correlations, and more representative control systems. These changes have consistently improved the accuracy of the ODYN code and reduced the uncertainty in its predictions compared against the qualification tests. Recently, the ODYN model has been approved by the NRC for application to all GE BWR plant transients.

Q31. How does the ODYN code model the behavior of BWRs such as VY during large transients?

A31. (JLC) The ODYN code models BWR vessel physical components, mechanical equipment functions, control systems and nuclear/thermal-hydraulic phenomena. The simulation involves describing the physical plant in the model (i.e., volumes, flow paths, resistances), establishing the desired operating conditions (i.e., water level, power, pressure) and introducing a disturbance (i.e., valve closure, pump trip, control action). The ODYN model predicts the plant response behavior based on its physical model correlations.

The ODYN analyses assume operational configurations and component/system failures that bound (i.e., represent more severe conditions than) the transients that would occur during normal plant operations or design basis events, including large transients.

Q32. What is your understanding of the term "design codes"?

A32. (JLC) Design codes are the computer simulation models applied in analyses to ensure that the structures, systems and components in a nuclear power plant discharge their intended function during normal, transient and accident conditions. As such, design codes incorporate appropriate margins of conservatism.

Q33. What is your understanding of the term "best estimate codes"?

A33. (JLC) Best estimate codes are computer simulation models applied in analyses intended to accurately predict the actual behavior of a nuclear power plant (or portions thereof) during normal operations, transients, or design basis accidents.

Q34. Which of the two terms, "design code" or "best estimate code", more accurately describes the operation of the ODYN code?

A34. (JLC) The ODYN code is accepted as a best estimate code, though it includes some conservative biases due to simplified aspects of the model. GE has qualified the ODYN code against all significant plant transients and the NRC has accepted that the ODYN code is a dependable best estimate code.

Q35. What is the impact of the nature of the ODYN code on the ability to obtain realistic predictions of plant behavior during the two large transients that are the subject of this contention?

A35. (JLC) As a best estimate code benchmarked against all significant transients, ODYN is capable of predicting accurately the plant behavior during transients occurring at higher EPU power levels.

Q36. Has the ODYN code been assessed against actual MSIV closure transients or load rejection transients at an operating facility?

A36. (JLC) Yes, the ODYN code has been benchmarked against all significant plant transients including turbine trips (equivalent in its effects to a generator load rejection test) and main steam valve isolation events. The turbine trip data were obtained from the Peach Bottom and KKM plants; the MSIV closure data were obtained from the Hatch plant.

The qualification of ODYN against the plant pressurization transients involved modeling each plant description and simulation of the transient. The ODYN code-predicted parameters are compared against the measured data, and the results of the comparison are used to determine the application basis of the ODYN results to licensing analyses.

Q37. Do the results of these benchmark assessments demonstrate the ability of the code to accurately predict plant performance during large transients?

A37. (JLC) Yes. The Peach Bottom turbine trip tests date back to the late 1970s and form the initial benchmark for pressurization transients and uncertainty margins for the ODYN code. All subsequent advanced versions of the ODYN code have been assessed against these tests and continue to form the basis for the code's accuracy. The current version of the ODYN code continues to accurately predict the overpower magnitude and slightly overpredict the overpressure magnitude vis-à-vis the Peach Bottom tests. The ODYN model was later also qualified against MSIV transient data and determined to also predict the peak pressure results conservatively, consistent with its approved application basis.

Q38. What other assessments have been made of the performance of the ODYN code and its ability to predict the behavior of BWRs such as Vermont Yankee during large plant transients?

A38. (JLC) The ODYN model was initially developed exclusively for the prediction of, and benchmarked against, fast pressure transients such as MSIV closure, turbine trips or GLRWBs. However, since that time, GE has expanded its qualification and application to include all other significant transients, such as recirculation flow and coolant temperature disturbances. The code has been determined to accurately predict plant behavior in those transients.

Q39. Do the large transient analyses compute the stresses that are imparted on mechanical components during the transients under uprate conditions?

A39. (JLC) The best estimate ODYN model is applied using bounding equipment performance and limiting initial conditions to predict the plant behavior. The resulting predicted parameters – principally pressure histories – are used to confirm that the reactor components and vessel meet the loads used in their design. With respect to large transients, the parameter of interest is the peak vessel pressure, whose design value is 1375 psig. The overpressure transient analysis is performed to confirm that the predicted peak pressure remains below this design value. No other loads on the vessel or its components are derived from the overpressure transient analyses. Therefore, stresses on components are not direct outputs of the ODYN simulations.

Q40. Have transient analyses been performed for MSIV closure and generator load rejection transients at VY occurring under EPU operation that bound the plant's behavior during those transients?

A40. (CJN) Yes. In advance of implementation of the EPU, GE prepared in December 2005 an updated Supplemental Reload Licensing Report ("SRLP") containing analyses of the performance of VY under EPU conditions. The SRLP contained, among others analyses, the results of licensing basis GLRWB and MSIV closure simulations conducted using the ODYN code. Copies of the pages of the SRLP that summarize the results of these simulations are included as Exhibit 8. The results of these simulations verified that: (1) these transients remain the limiting transients from the perspective of the selected parameters, and (2) the results remain within the design and license limits. Based on the benchmark results, the peak pressures calculated by ODYN would be overpredicted (conservatively high). These analyses still show significant margin to the limits. This type of analysis is performed as part of the core design for each operating cycle.

Q41. Why is it reasonable to conclude that the ODYN simulations of VY's behavior in large transients during EPU operation accurately predicts the actual plant response to those transients?

A41. (JLC) The ODYN model is qualified for the analysis of this type of transient and the resulting parameters are within the applicable physical correlations of the model for the bounding licensing analysis. Also, a VY LTT at the increased power condition at constant pressure would be significantly milder than the ODYN analyses. Several plant transients have been compared against ODYN predictions over the years to assess the specific BWR licensing basis. All of these comparisons have determined that the licensing predictions are bounding and that the plant equipment response is consistent with its design basis. Furthermore, GE has simulated in detail some of the transients for the purpose of revising the equipment response or setpoints in order to improve the plant response. None of these simulations has shown any ODYN model deficiency with respect to its licensing and qualification basis. Therefore, GE does not expect any model qualification benefit from the VY tests.

C. Technical Bases for Not Performing LTT at VY under EPU Operation

Q42. Besides the results of the ODYN analyses that you just described, is there a technical justification for excusing VY from performing LTT under EPU operations?

A42. (CJN, JLC) Yes. There are several sound technical bases that support Entergy's request for an exception from performing LTT at VY under uprate operations.

Q43. What are these bases?

A43. (CJN, JLC) They include: (1) the behavior of other plants that have experienced large transients during EPU operations; (2) the results of LTT conducted at an European plant similar to VY; (3) VY's responses to unplanned transients; (4) the regime of periodic component and system testing at VY; and (5) the similarity in VY's pre- and post- EPU design configuration and system functions. From these technical bases, it is reasonable and justifiable to conclude that the effects at EPU conditions can be analytically determined on a plant-specific basis without the need for actual transient testing. The transient analyses performed for the VY EPU demonstrate that all safety criteria are met and the uprate does not cause any previously non-limiting transient to become limiting.

D. Industry Experience Confirming the Transient Analysis Methodology

Q44. What industry experience confirms the basic transient analysis methodology used by Entergy at VY?

A44. (JLC) Of the thirteen BWR plants that have implemented EPUs without increased reactor operating pressure, four (Hatch 1 and 2, Brunswick 2, and Dresden 3) have experienced one or more unplanned large transients from uprated power levels. Specifically:

- Southern Nuclear Operating Company's ("SNOC") application for EPU of Hatch Units 1 and 2 was granted without a requirement to perform large transient testing. VY and Hatch are both BWR/4 plants with Mark I containments. Hatch Unit 2 experienced a post-EPU unplanned transient that resulted in a generator load rejection from approximately 111% OLTP (98% of uprated power) in May 1999. As noted in SNOC's LER 1999-005-00 (attached as Exhibit 9), all systems functioned as expected and no anomalies were seen in the plant's response to this transient.

- Hatch 2 also experienced a post-EPU reactor trip on high reactor pressure as a result of MSIV closure (from 113% OLTP (100% of uprated power)) in 2001. As noted in SNOC's LER 2001-003-00 (attached as Exhibit 10), all systems functioned as expected and designed, given the conditions experienced during the transient.

- In addition, Hatch Unit 1 has experienced two post-EPU turbine trips from 112.6% and 113% of OLTP (99.7% and 100% of uprated power) as reported in SNOC LERs 2000-004-00 and 2001-002-00, respectively (copies attached as Exhibits 11 and 12). Again, the behavior of the primary safety systems was as expected. No new plant behaviors for either plant were observed. The Hatch operating experience shows that the analytical models being used (which are the same as those in use at VY) are capable of modeling plant behavior at EPU conditions.

- As discussed earlier, Progress Energy's Brunswick Units 1 and 2 – which are very similar in design to VY – were licensed to uprate their power output to 120% of OLTP. Brunswick Unit 2 experienced a post-EPU unplanned transient that resulted in a generator/turbine trip due to loss of generator excitation from 115.2% OLTP (96% of uprated thermal power) in the fall of 2003. As noted in Progress Energy's LER 2003-004-00 (attached as Exhibit 13), no anomalies were experienced in the plant's response to this transient, and no unanticipated plant behavior was observed. The Brunswick operational experience shows that the analytical models being used (which are the same as those used at VY) are capable of modeling primary and secondary plant behavior at EPU conditions.

- Exelon Generating Company LLC's applications for EPU for Quad Cities Units 1 and 2, and Dresden Units 2 and 3 were granted without requiring the performance of LTT. The Quad Cities and Dresden units are plants similar to VY, featuring Mark I containments. Dresden 3 has experienced several turbine trips and a generator load rejection from high uprated power conditions. In January 2004, Dresden 3 experienced two turbine trips from 112.3% and 113.5% of OLTP (96% and 97% of uprated power) as reported in Exelon LERs 2004-001-00 and 2004-002-00, respectively (attached as Exhibits 14 and 15). The plant response was as predicted in the transient analyses, which used the same methodology as those performed at VY. The plant response indicates that the analytical models used for transient analyses are capable of accurately predicting transient plant behavior at EPU conditions.

- Similar plant response was observed in May 2004, when Dresden 3 also experienced a loss of offsite power which resulted in a turbine trip on Generator Load Rejection from 117% of OLTP (100% of uprated power). See Exelon LER 2004-003-00 (attached as Exhibit 16).

The fact that the Hatch, Brunswick, and Dresden plants, all of which are similar in design to VY, experienced no anomalous response to large transients from EPU operating levels supports the conclusion that VY should also respond as predicted to large transients during EPU operation.

Q45. Was the ODYN code used to provide the bounding transient analyses for all of these plants?

A45. (JLC) Yes. In every instance in which unplanned large transients from EPU power levels have been experienced at these plants and an analysis of the scenario involved in the transients existed, the plant's response was bounded by the analyses performed using ODYN and no new phenomena were exhibited in the response.

E. Industry experience with Large Transient Testing

Q46. Has LTT been performed on any plant after an EPU, and if so what were the test results?

A46. (JLC) Yes. The KKL (Leibstadt) power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 104.2% OLTP to 119.7% OLTP. KKL testing for major transients involved turbine trips at 113.4% OLTP and 116.7% OLTP, and a generator load rejection test at 104.2% OLTP.

The response of the KKL reactor and other plant equipment during those large transient tests was satisfactory and was bounded by the ODYN code predictions for that plant.

Q47. How did the response of the KKL plant to a turbine trip transient compare to the analytical predictions made by the ODYN code?

A47. (JLC) A comparison of the KKL turbine test transient performance against the ODYN predictions shows consistency between the test results and those predicted in the model's qualification, as well as in other comparisons between ODYN runs and plant operating data. In all cases, the ODYN model slightly overpredicts vessel peak pressure. The KKL turbine trip test is an excellent prediction of what a test at VY would show because KKL has a 2% higher power density than VY and both plants are of a full turbine bypass capacity design.

Q48. NEC alleges (December 22, 2005 Answer to Entergy's Statement of Material Facts Regarding NEC Contention 3, para. 20) that since KKL is a foreign reactor not subject to NRC regulation, the KKL test results are irrelevant to the VY EPU, and that even if relevant, there is no ready means of reconciling regulatory data to those applicable to VY. Are these allegations valid?

A48. (JLC) No. Plant test performance is a physically observable phenomenon, which can be objectively measured and is independent of the regulatory regime. Furthermore, the same ODYN analytical model as used for VY was applied to simulate this test.

F. VY Operating Experience

Q49. Has VY experienced large transients during its operating lifetime?

A49. (CJN) Yes. VY has previously experienced the following unplanned large transients:

- On 3/13/1991, with the reactor at full power, a reactor SCRAM occurred as a result of Turbine/Generator Trip on Generator

Load Rejection due to a 345 kV Switchyard Tie Line Differential Fault. This transient was reported to the NRC in LER 1991-005-00, dated 4/12/91 (attached as Exhibit 17).

- On 4/23/1991, with the reactor at full power, a reactor SCRAM occurred as a result of a turbine/generator trip on generator load rejection due to the receipt of a 345 kV breaker failure signal. The transient included a loss of offsite power. This was reported to the NRC in LER 1991-009-00, dated 05/23/91 (attached as Exhibit 18).

- On 6/15/1991, during normal operation with reactor at full power, a reactor SCRAM occurred due to a Turbine Control Valve Fast Closure on Generator Load Rejection resulting from a loss of the 345 kV North Switchyard bus. This transient was reported to the NRC in LER 1991-014-00, dated 7/15/91 (attached as Exhibit 19).

- On 6/18/2004, during normal operation with the reactor at full power, a two phase electrical fault-to-ground caused the main generator protective relaying to isolate the main generator from the grid and resulted in a Generator Load Rejection reactor SCRAM. This transient was reported to the NRC in LER 2004-003-00, dated 8/16/2004 (attached as Exhibit 20).

- On 7/25/2005, during normal operation with the reactor at full power, a generator load rejection SCRAM occurred due to an electrical transient in the 345 kV Switchyard. This transient was reported to the NRC in LER 2005-001-00 (attached as Exhibit 21).

Q50. Did VY perform as expected in response to these transients?

A50. (CJN) Yes. No significant anomalies were seen in the plant's response to these transients. The performance of VY in the transients it experienced at pre-EPU power levels was well within the bounds of the ODYN analyses.

Q51. Does VY's historical response to large transients provide a basis for an exception to LTT?

A51. (CJN) Yes. In particular, the transients in 2004 and 2005 occurred after most of the modifications associated with EPU were already implemented, including the new HP turbine rotor, Main Generator Stator rewind, the new high pressure feedwater heaters, condenser tube staking, an upgraded isophase bus duct cooling system, and condensate demineralizer filtered bypass. In each instance, the modified or added equipment functioned normally during the transient. The plant's performance during these recent transients, including that of the modified components, demonstrates that the EPU modifications do not significantly affect the plant's response during transient conditions.

G. System and component testing

Q52. Does system and component testing during normal operations provide a basis for an exception to LTT?

A52. (CJN) Yes. Technical Specification-required surveillance testing (e.g., component testing, trip logic system testing, simulated actuation testing) is routinely performed during plant operations. Such testing demonstrates that the structures, systems and components ("SSCs") required for appropriate transient performance will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis.

Q53. How often are the main components involved in large transients tested?

A53. (CJN) The MSIVs are tested quarterly. The safety relief valves and spring safety valves are tested once every operating cycle. These valves are required to perform in accordance with the design during large transients; their periodic testing assures that their performance during large transients will be acceptable. Likewise, the reactor protection system instrumentation that is relied on to mitigate large transients is tested quarterly, assuring that it will carry out its design function in the event of a large transient.

Q54. What is the significance of the system and component testing program?

A54. (CJN) Because the characteristics and functions of SSCs are tested periodically during plant operations, they do not need to be demonstrated further in a large transient test. In addition, limiting transient analyses (i.e., those that affect core operating and safety limits) are re-performed for each operating cycle and are included as part of the reload licensing analysis.

H. Similarities in pre- and post-EPU plant design and physical configuration

Q55. Are there similarities in design and system function between the pre- and the post-EPU VY plant configuration?

A55. (CJN) There are great similarities. While some operating parameters (e.g., core power distribution) have been modified to accommodate EPU operation and some setpoint changes were made, these changes do not measurably contribute to response to large transients. None of the modifications that have been made will introduce new thermal-hydraulic phenomena as a result of power uprate, nor are any new system interactions during or as the result of analyzed transients introduced. No systems have been added or changed at VY that are required to mitigate the consequences of the large transients that would be the subject of the LTT.

Operationally, the EPU modifications have no significant effect on plant transient analysis because, since the uprate is a constant pressure uprate, most of the plant's systems will operate in the same manner as before the uprate. Also, the VY EPU is performed without a change in operating reactor dome pressure from current plant operation.

Q56. Have there been major equipment modifications or new hardware installations at VY that could result in different large transient performance than that predicted by the analyses and the plant's prior operating history?

A56. (CJN) No. Table 1 (attached) provides: (a) a listing of EPU plant modifications, all of which were implemented during VY's last two Refueling Outages (RFO 24 and RFO 25, in Spring 2004 and Fall 2005, respectively); (b) a determination of whether the modifications have an effect on the plant transient analysis; (c) a determination of whether the modifications are modeled in the transient analyses; (d) an indication of completed post modification testing; (e) an indication of subsequent power ascension and/or power operation confirmatory testing and monitoring; and (f) a determination of whether the modified function would be tested/verified during large transient testing.

Most of the EPU modifications were made to non-safety-related components, which are not credited in licensing basis transient analyses. Incidental modifications associated with EPU, such as alarms, indications, and scaling changes, also do not impact transient response.

Q57. How does the number of modifications and new equipment installations included in the VY EPU provide a basis for an exception to LTT?

A57. (CJN) Not only are the equipment modifications and additions relatively few but none of these modifications will introduce any new thermal-hydraulic phenomena as a result of the power uprate.

Nor are any new system interactions during or as the result of analyzed transients introduced.

I. Impact of LTT on plant systems and components

Q58. Would performance of LTT have an adverse impact on the plant?

A58. (CJN, JLC) The performance of a SCRAM from high power, such as those that take place during LTT, results in an undesirable transient cycle on the primary system. The occurrence of primary system transient cycles should be minimized, since they introduce unnecessary stresses on the primary system components. The undesirable effects of performing the tests outweigh the benefits of any limited additional information that may be gained from them.

In addition, performance of each LTT causes a plant shutdown. Any plant shutdown results in a generation outage for a period of time (typically 2-3 days) for the plant. Since there are no measurable safety benefits to be derived from the performance of the tests, the loss of generation revenue and other costs associated with the performance of the tests cannot be economically justified.

J. Endorsement of LTT exception by ACRS

Q59. Has the Advisory Committee on Reactor Safeguards examined the LTT exception sought by Entergy for the VY EPU?

A59. (CJN)Yes. In its letter to the NRC Chairman following its review of the VY EPU, the Advisory Committee on Reactor Safeguards concluded:

> 3. Load rejection and main steam isolation valve closure transient tests are not warranted. The planned transient testing program adequately addresses the performance of the modified systems.

Letter from Graham B. Wallis to NRC Chairman Nils Diaz dated January 4, 2006, attached as Exhibit 22.

IV. SUMMARY AND CONCLUSIONS

Q60. Please summarize your testimony.

A60. (CJN, JLC) Our testimony can be summarized as follows:

- **Previous industry operating and LTT experience**

Operating experience at other plants that have implemented a constant pressure power uprate such as that implemented by Entergy at VY has shown that the transient analysis results bound the performance observed during actual operational transients. This industry operating experience is applicable to VY because of the similarity in its design to that of those plants. The results of LTT at one plant similar to VY also confirm the validity of the analytical predictions of VY's response to LTT under EPU operating conditions.

- **Previous VY operating experience**

Previous operating experience at VY for large transients has shown that the plant has performed as expected, and that its performance during transients is bounded by the transient analyses of record for the facility. This operating experience includes transients in 2004 and 2005, which occurred after the completion of many of the plant modifications being implemented in preparation for the EPU. The plant's performance during the 2004 and 2005 transients demonstrates that the EPU modifications do not significantly affect the plant's response during transient conditions.

- **Absence of new thermal-hydraulic phenomena or system interactions**

The operation of VY after the EPU will result in different operating parameters (e.g., feedwater flow, moisture carryover) but will not result in any new thermal-hydraulic phenomena in the event of a plant transient. The modifications already implemented have no significant effect on plant transient analysis because, since the uprate is a constant pressure uprate, most of the plant's systems will operate in the same manner as before the uprate.

- **No net benefits from LTT**

The benefits from conducting LTT would be minimal and would be outweighed by the potential adverse impact of LTT on the plant's systems and components.

- **Significant costs associated with performance of LTT**

Performance of LTT causes a plant shutdown. Any plant shutdown results in a generation outage for a period of time (typically 2-3 days) for the plant. Since there are no measurable safety benefits to be derived from the performance of the tests, the loss of generation revenue and other costs associated with the performance of the tests cannot be justified.

Q61. What are your conclusions regarding the assertions in NEC Contention 3?

A61. (CJN, JLC) We conclude that there is no support for the claims made in NEC Contention 3. The extensive and conservative engineering analyses, historical test and actual transient data, individual component testing, and observed performance at other plants experiencing large transients provide reasonable assurance and confidence that VY systems will function as designed in mitigation of large transients from EPU conditions. The potential benefits, if any, from LTT at VY are significantly outweighed by the adverse effect on plant systems and components from the tests themselves. VY's request for an exception to LTT, therefore, is reasonable and poses no threat to public health and safety.

Q62. Does that conclude your testimony?

A62. (CJN, JLC) Yes, it does.

Table 1: VY Equipment Modifications Implemented for EPU

Modification	Description	Potential Impact on Transient Response?	Post Mod Testing	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Main turbine – LP diaphragm replacement	Replace 8th stage diaphragm of LP turbine	No	Vibration baseline measurements	Vibration monitoring	NA
Main turbine cross-around relief valves (CARVs) and Discharge Piping	Install higher capacity relief valves	No	In-service Leak check	Monitor temperature downstream of CARVs	No
Main generator -rewind	Rewind/upgrade main generator for CPPU conditions. Replace generator hydrogen coolers with upgraded coolers	No	• Performance test • AC Hi-Pot test each phase • Pressure and vacuum testing • Winding resistance • Meggering	• Monitor generator and cooling	• No
Main condenser	• Stake main condenser tubing to reduce the effects of flow induced vibration	No	• Leak check tubes • Monitor chemistry	• Monitor chemistry	• No
Feedwater heater 4A/B shell side relief valve	• Replace relief valves with larger capacity relief valve to accommodate increased feedwater flow	No	• Bench test valves • Leak test installation	NA	• No
Steam dryer cover plate strengthening	• Replace lower cover plates with thicker plates • Add reinforcing stiffeners at lower cover plates and vertical hood sides • Remove internal brackets in top inside corners of outer hoods • Replace vertical hood and hood top plates with thicker plates • Replace/Upgrade tie bars	No	• Inspection	• Vibration and moisture carryover monitoring during power ascension per power ascension test plan (PATP)	• No
Isolated phase bus duct cooling	• Install a new isolated phase bus duct cooling system to remove bus duct heat under CPPU conditions	No	• Monitor bus duct cooling • Flow tests	• Performance monitoring	• No

Modification	Description	Potential Impact on Transient Response?	Post Mod Testing	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
HP feedwater heater replacement	• #1A, #1B, #2A, and #2B feedwater heater replacement	No	• Pressure test • Visual inspection • Magnetic particle testing • Radiography • In-service inspection • Thermal performance demonstration	• Performance monitoring	• No
Residual heat removal service water (RHRSW) system	• Modify RHRSW pumps (Train A and B) Motor Bearing Oil Coolers piping to recover Service Water flow from the coolers	No	• Visual Inspection • Particle Testing • Ultrasonic Flow Testing • In-Service Inspection	NA	• No
NSSS/torus attached piping	• Upgrade particular NSSS and torus attached piping supports	No	• Welds to be examined by visual, liquid penetrant, magnetic particle, as applicable	NA	• No
Flow induced vibration (FIV)	• Install FIV instrumentation	No	• Verify installation	• Collect EPU data and analyze	• No
Reactor recirculation (RR) system runback	• Provide rapid runback of RR pump from high power on trip of condensate or feedwater pump	No	• Channel Calibration • Test with breakers in "test" and RR system not operating	NA	• No
Condensate demineralizer	• Install condensate demineralizer filtered bypass strainer to permit one demineralizer to be removed under CPPU conditions	No	• Monitor chemistry • Establish flow baseline measurements	• With filtered bypass in service, monitor flows under various EPU conditions • Monitor reactor water chemistry	• No
Feedwater system suction pressure trip	• Protect feed pumps (RFP) with two sequential levels of low suction pressure trips at various time delays to ensure only one pump trips at a time and for high power RR pump runback to ~60% on loss of a Feed Pump • Modify trip logic to prevent common mode failure due to loss of RFP low flow circuits	No	• Channel calibration • Test with breakers in "Test" position	NA	• No
Cooling tower/fan motors	• Replace fan blades with more efficient blades and drive motors with upgraded higher performance motors	No	• Cooling tower performance monitoring	NA	• No

Modification	Description	Potential Impact on Transient Response?	Post Mod Testing	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
EQ Upgrades	• Reroute feed to SRV monitor to new breaker	No	• Voltage check and megger	NA	• No
Grid Stability	• Increase the rating (million volt-ampere (MVA)) of the Vermont Yankee-Northfield 345kV line from 896 MVA to a minimum rating of 1075 MVA • Increase MVA rating on the Ascutney-Coolidge 115 kV line from 205 MVA to 240 MVA • Addition of 60 MVAr of shunt capacitors at the Vermont Yankee 115 kV bus • Modification to provide a second primary protection scheme on the Vermont Yankee north bus • Addition to provide a second primary protection scheme on the Vermont Yankee main generator • Independent pole tripping on the Vermont Yankee 381 breaker • Addition of out of step protection for the Vermont Yankee generator	No	• Voltage checks • Logic checks • Relay calibration	• In-service testing of the 345kV and 115 kV primary/ secondary protective relay, line carrier system (Monthly)	• No
Main turbine – HP flow path	• Replace HP Turbine steam path (new HP diaphragms and rotor) • New control cams, camshafts and hydraulics New control valve settings • Modify control valve operating mechanism with 5% margin above CPPU • Modify turbine control and overspeed setpoint for CPPU conditions • New Hydrogen Coolers	No	• Factory 120% trip test • Overspeed testing • Control and stop valve response testing • Vibration baseline measurements • EPR and MPR tuning	• Overspeed testing • Vibration monitoring • EPR and MPR Testing per Power Ascension Test Plan (PATP) • Control and stop valve testing	• No

Modification	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Testing	EPU Startup Testing	Further Tested by Turbine Trip / Main Steam Isolation Valve Closure
Electronic pressure regulator (EPR) setpoint change	• Change in EPR setpoint control range and zero power setpoint based on higher steam line differential pressure (dp) • Rescale bypass relay to account for bypass valve capability of 89% of total steam flow • Expand EPR control band from current range of 900 to 1000 psig a new range of 850 to 1000 psig • Install signal isolators to minimize EPR output test wiring fault from negatively affecting EPR operation • Add second notch filter function to programmable logic controller (PLC) software and tune to remove an 8.8 Hz signal	Yes	Yes	• Wire continuity checks • PLC calibration • EPR and MPR tuning	• EPR and MPR testing per PATP	• No

Modification	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Testing	EPU Startup Testing	Further Tested by Turbine Trip / Main Steam Isolation Valve Closure
Main steam line high flow setpoint	• Respan transmitters to encompass new 140% steam flow values • Replace the 4 transmitters used to provide 40% setpoint for MSL high flow reduced function with more accurate transmitters • Setpoint changes for 140% isolation at new steam flows • Install new indicators on master trip units	Yes	Yes	• Channel calibration • Test circuit logic	• TS required channel check and calibration	• No
Neutron monitoring setpoints – APRM and RBM	• APRM flow biased SCRAM setpoints and rod block limits require changes due CPPU • APRMs require recalibration reflecting CPPU rated power operation • RBMs require recalibration reflecting CPPU rated power operation	Yes	Yes	• Channel calibration • Test circuit logic	• TS required channel check and calibration	• No
Rod worth minimizer (RWM) - setpoint	• Setpoint change to maintain the setpoint at the same absolute value of steam flow due to the range changes of the associated instruments	Yes	Yes	• Channel calibration • Test circuit logic	• TS required channel check and calibration	• No
Turbine first stage pressure	• Setpoint changes for the SCRAM bypass	Yes	Yes	• Channel calibration • Test circuit logic	• No. (TS required channel check and calibration)	• No

Modification	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Testing	EPU Startup Testing	Further Tested by Turbine Trip / Main Steam Isolation Valve Closure
Feedwater Isokinetic Probes	• Replace Sample Probes	No	No	• Leak Check process boundary	• No	• No
Feedwater Pump Automatic Trip	• Trip Feedwater Pump on Loss of Condensate Pump	No	No	• Circuit/Logic Tests	• Yes - Condensate Pump Trip Test	• No

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC. (Vermont Yankee Nuclear Power Station)	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)

AFFIDAVIT OF JOSE L. CASILLAS RE NEC CONTENTION 3 TESTIMONY

County of Santa Clara)
)
State of California)

I, Jose L. Casillas, being duly sworn according to law, depose and state the following:

1. I am the Plant Performance Consulting Engineer in the Nuclear Analysis group of the Engineering organization of GE Nuclear Energy. My business address is 1989 Little Orchard Street, San Jose, California, 95125.

2. I am providing testimony, dated May 17, 2006, on behalf of Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. in the above captioned proceeding, entitled "Testimony of Craig J. Nichols and Jose L. Casillas on NEC Contention 3 – Large Transient Testing."

3. The factual statements and opinions I express in the cited testimony are true and correct to the best of my personal knowledge and belief.

4. I declare under penalty of perjury that the foregoing is true and correct.

Further, the affiant sayeth not.

Jose L. Casillas
Jose L. Casillas

Subscribed and sworn to before me
this 15th day of May, 2006

Christina M. Garcia
Notary Public

My commission expires July 2, 2009

CHRISTINA M. GARCIA
Commission # 1590414
Notary Public - California
Santa Clara County
My Comm. Expires Jul 2, 2009

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	Docket No. 50-271
ENTERGY NUCLEAR VERMONT YANKEE, LLC and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 04-832-02-OLA (Operating License Amendment)
(Vermont Yankee Nuclear Power Station)	)	

AFFIDAVIT OF CRAIG J. NICHOLS RE NEC CONTENTION 3 TESTIMONY

County of Windham)
)
State of Vermont)

I, Craig J. Nichols, being duly sworn according to law, depose and state the following:

1. I am the Extended Power Uprate Project Manager for Entergy Nuclear Operations, Inc. My business address is 320 Governor Hunt Road, P.O. Box 250, Vernon, VT 05354.

2. I am providing testimony, dated May 17, 2006, on behalf of Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. in the above captioned proceeding, entitled "Testimony of Craig J. Nichols and Jose L. Casillas on NEC Contention 3 – Large Transient Testing."

3. The factual statements and opinions I express in the cited testimony are true and correct to the best of my personal knowledge and belief.

4. I declare under penalty of perjury that the foregoing is true and correct.

Further, the affiant sayeth not.

Craig J. Nichols

Subscribed and sworn to before me
this 15th day of May, 2006

Notary Public

My commission expires 5/5/2006

Resume of Craig Joseph Nichols

178 Forest Avenue
West Swanzey, NH 03446
(603) 358-6452

EMPLOYMENT

Entergy Nuclear Operations, Inc. – Vermont Yankee **July 2002 to Present**

Change in employment due to sale of Vermont Yankee.

Project Manager – Power Uprate **July 2002 to Present**

- ❖ Provide overall project management for an Extended Power Uprate at Vermont Yankee. Includes all engineering, analyses, modifications, implementation, fiscal and project management for the most comprehensive site project since original plant startup.
- ❖ BWR Owners Group Maintenance Committee Chairman.
- ❖ Key Management Role as Station Duty Call Officer
- ❖ Refuel Outage Support – Emergent Issues (MSIVs) and Outage Execution

Vermont Yankee Nuclear Power Corporation **1989 to July 2002**

Various positions of increasing responsibility in production, project management, and support in the areas of Electrical, I&C, Planning and Scheduling, and Engineering. Responsibilities have included management of large projects and personnel groups, interaction of newly created organization, and leadership of maintenance and site efforts to identify constraints and improve economic viability.

Manager – Power Uprate **December 2001 to Present**

- ❖ Newly created position to provide overall project management for an Extended Power Uprate at Vermont Yankee. Includes all engineering, analyses, modifications, implementation, fiscal and project management for the most comprehensive site project since original plant startup

Maintenance Support Manager **April 2000 to December 2001**

- ❖ Newly created position responsible to oversee and integrate all Maintenance Division support functions including project planning and implementation, component engineering and program management.
- ❖ Achieved Plant Certification for BWR

I&C Manager **January 1999 to April 2000**

- ❖ Lead effort to improve human performance and training programs for I&C technicians.
- ❖ Implement and modernize all engineering programs and projects.

Electrical and Controls Maintenance Manager **January 1997 to January 1999**

- ❖ New position created during reorganization of Maintenance Departments.
- ❖ Initial task to integrate operations of electrical and I&C groups within E&CM and the three Maintenance Departments.
- ❖ Management of E&CM projects and budget in support of company goals.

Acting Maintenance Manager **October 1996 to January 1997**

- Successful completion of 1996 Refuel Outage including recovery from MSIV PCLRT failures.
- Development and pursuit of Maintenance Department reorganization to address areas for improvement and create organization for long-term performance.

Planning and Scheduling Supervisor **April 1996 to September 1996**

- Assigned responsibility to improve Department Planning and Scheduling activities.
- Developed draft for 12-week schedule preparation guideline.
- Initiated efforts to reduce backlogs of CMs and PMs, unplanned work orders, and unscheduled activities.

Electrical Maintenance Production Supervisor **1991 to March 1996**

Senior Maintenance Engineer – Electrical **1989 to 1991**

Yankee Atomic Electric Company **1983 to 1989**

Electrical Engineer for design modification and project implementation for Vermont Yankee and Seabrook Stations.

Cooperative Education Student Assignments **1981 to 1983**

Engineering Assistant and Draftsman at Stone & Webster Engineering Corporation

EDUCATION

BSEE (Power Systems) **1985**

NORTHEASTERN UNIVERSITY
BOSTON, MASSACHUSETTS
Magna Cum Laude and Cooperative Education Award

REFERENCES

Available upon request

JOSÉ L CASILLAS

Current Title

Consulting Engineer in BWR Plant Performance,
Nuclear Analysis, Engineering, GE Nuclear Energy.

Nuclear Experience

BWR Simulator Training.
BWR System Fundamentals.

Education

BS Mechanical Engineering 1973,
University Of California, Davis.

Advanced Training and Certification

None.

Qualifications Summary

Areas of Expertise:

- BWR Plant System Performance Evaluation.
- BWR Transient and Loss-of Coolant Accident Analysis.
- Design, Licensing and Operation of BWR Cores.
- Thermal Hydraulic Design and Evaluation of BWR Fuel.

Experience

<u>GENERAL ELECTRIC COMPANY - 33 YEARS</u>

- Plant Performance Consulting Engineer/Engineering Fellow, 2002-present.
- Analysis Consultant, Nuclear & Safety Analysis, 1998-2002.
- Technical Account Manager, Engineering & Licensing Consulting Services, 1995-1997.
- Project Manager, Shroud Cracking Safety Evaluations, 1994-1995.
- Technical Leader, Reload Nuclear Engineering, 1984-1994.
- Technical Leader, Plant Performance Engineering, 1980-1984.
- Senior Engineer, ECCS/Containment Performance Engineering, 1977-1980.
- Engineer, Core Thermal Hydraulic Analysis, 1973-1977.

May 2006.

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
A. SITE					
1.	Location	Brunswick County, North Carolina	Limestone Co., Alabama	Nemaha Co., Nebraska	Appling Co., Georgia
2.	Size of Site (Acres)	1,200	840	1,090	2,100
3.	Site Ownership	CP&L	U.S. Government	CPPD	GPC
4.	Plant Ownership	CP&L	TVA	CPPD	GPC
5.	Number of Units on Site	2	3	1	2
B. PLANT-REACTOR WARRANTED CONDITIONS					
1.	Net Electrical Output (Mwe)	821	1,075/unit	770	786
2.	Gross Electrical Output (Mwe)	849	1,098/unit	801	813
3.	Turbine Heat Rate (Btu/kW-hr)	10,120	10,243	10,187	10,227
4.	Gross Plant Heat Rate (Btu/kW-hr)	9,816	10,231	10,142	10,218
5.	Feedwater Temperature (°F)	420	376.1	367	387.4
C. REACTOR PRIMARY VESSEL					
1.	Inside Diameter (ft-in.)	18-2	20-11	18-2	18-2
2.	Overall Length Inside (ft-in.)	69-4	72-0	69-4	69-4
3.	Design Pressure (psig)	1,250	1,250	1,250	1,250
4.	Wall Thickness (in.) (including clad)	5-17/32	6-5/16	5-17/32	5-17/32

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

	Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1

D. REACTOR COOLANT - RECIRCULATION LOOPS

1.	Location of Recirculation Loops	Primary Containment System Drywell Structure	Primary Containment System Drywell Structure	Primary Containment System Drywell Structure	Primary Containment System Drywell Structure
2.	Number of Recirculation Loops	2	2	2	2
3.	Pipe Size (in.)	28	28	28	28
4.	Pump Capacity, each (gpm)	45,200	45,000	45,200	45,200
5.	Number of Jet Pumps	20	20	20	20
6.	Location of Jet Pumps	Inside Reactor Primary Vessel	Inside Reactor Primary Vessel	Inside Reactor Primary Vessel	Inside Reactor Primary Vessel

E. REACTOR

1.	Reactor Warranted Conditions				
	a. Thermal Output (Mwt)	2,436	3,293	2,381	2,436
	b. Reactor Operating Pressure (psig)	1,005	1,005	1,005	1,005
	c. Total Reactor Core Flow Rate (lb/hr)	77.0×10^6	102.5×10^6	74.5×10^6	78.5×10^6
	d. Main Steam Flow Rate (lb/hr)	10.47×10^6	13.38×10^6	9.81×10^6	10.03×10^6
2.	Reactor Core Description				
	a. Lattice	7 x 7	7 x 7	7 x 7	7 x 7
	b. Pitch of Movable Control Rods (in.)	12.0	12.0	12.0	12.0
	c. Number of Fuel Assemblies	560	764	548	560

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	d. Number of Movable Control Rods	137	185	137	137
	e. Effective Active Fuel Length (in.)	144	144	144	144
	f. Equivalent Reactor Core Diameter (in.)	160.2	178.1	158.5	160.2
	g. Circumscribed Reactor Core Diameter (in.)	170.5	198.6	170.5	170.5
	h. Total Weight UO_2	272,850	372,373	267,095	272,850
3.	Reactor Fuel Description				
	a. Fuel Material	UO_2	UO_2	UO_2	UO_2
	b. Fuel Density % of Theoretical	93	93	93	93
	c. Fuel Pellet Diameter (in.)	0.487	0.487	0.487	0.487
	d. Fuel Rod Cladding Material	Zircaloy-2	Zircaloy-2	Zircaloy-2	Zircaloy-2
	e. Fuel Rod Cladding Thickness (in.)	0.032	0.032	0.032	0.032
	f. Fuel Rod Cladding Process	Free Standing Loaded Tubes	Free Standing Loaded Tubes	Free Standing Loaded Tubes	Free Standing Loaded Tubes
	g. Fuel Rod Outside Diameter (in.)	0.563	0.563	0.563	0.563
	h. Length of Gas Plenum (in.)	16.0	16.0	16.0	16.0
	i. Fuel Rod Pitch (in.)	0.738	0.738	0.738	0.738
	j. Fuel Assembly Channel Material	Zircaloy-4	Zircaloy-4	Zircaloy-4	Zircaloy-4

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
4.	Reactor Control				
	Control Rods				
	a. Number	137	185	137	137
	b. Shape	Cruciform	Cruciform	Cruciform	Cruciform
	c. Material	B_4C Granules Compacted in SS Tubes	B_4C Granules Compacted in SS Tubes	B_4C Granules Compacted in SS Tubes	B_4C Granules Compacted in SS Tubes
	d. Pitch (in.)	12.0	12.0	12.0	12.0
	e. Poison Length (in.)	143.0	143.0	143.0	143.0
	f. Blade Span (in.)	9.75	9.75	9.75	9.75
	g. Number of Control Material Tubes for Rod	84	84	84	84
	h. Tube Dimensions (in.)	0.188 ODx0.025-wall	0.188 ODx0.025-wall	0.188 ODx0.025-wall	0.188 ODx0.025-wall
	i. Stroke (in.)	144.0	144.0	144.0	144.0
5.	Thermal Hydraulic Data				
	a. Heat Transfer Area per Assembly (ft^2)	86.513	86.513	86.513	86.513
	b. Reactor Core Heat Transfer Area (ft^2)	48,451	66,098	47,409	48,451
	c. Maximum Heat Flux* (Btu/hr ft^2)	428,100	425,000	427,820	428,308
	d. Average Heat Flux* (Btu/hr ft^2)	164,410	163,200	164,500	164,740
	e. Maximum Power per Fuel* Rod Unit Length (kW/ft)	18.5	18.4	18.5	18.5

* *These items are shown at design limits rather than design point.*

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	f. Average Power per Fuel* Rod Unit Length (kW/ft)	7.10	7.049	7.079	7.11
	g. Maximum Fuel Temperature (°F)	4,380	4,380	4,380	4,380
	h. Minimum Critical Heat Flux Ratio	1.9	1.9	1.9	1.9
	i. Total Heat Generated in Fuel (%)	95.0	95.0	95.0	95.0
	j. Core Average Exit Quality	13.6	13.2	13.2	13.0
6.	Power Distribution – Peaking Factors (Peak/Average)				
	a. Axial	1.50	1.50	1.50	1.50
	b. Relative Assembly	1.40	1.40	1.40	1.40
	c. Local (within assembly)	1.24	1.24	.1.24	1.24
	d. Total Peaking Factor	2.6	2.6	2.6	2.6
7.	Nuclear Design Data				
	a. Average Discharge Exposure – 1st core	19,000 MWD/ short ton U	19,000 MWD/ short ton U	19,000 MWD/ short ton U	19,000 MWD/ short ton U
	b. Moderator to Fuel Volume Ratio at Total Core H_2O/UO_2 cold	2.41	2.41	2.41	2.41
8.	In-Core Neutron Instrumentation				
	a. Number of In-Core Neutron Detectors	124	172	124	124

* *These items are shown at design limits rather than design point.*

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	b. Number of In-Core Detector Strings	31	43	31	31
	c. Number of Detectors per String	4	4	4	4
	d. Number of Flux Mapping Neutron Detectors	4	5	4	4
	e. Range (and Number) of Detectors				
	1) Source Range Monitor	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)	Source to 10^{-3}% power (4)
	2) Intermediate Range Monitor	10^{-4} to 10% power (8)	10^{-4} to 10% power (8)	10^{-4} to 10% power (8)	10^{-4} to 10% power (8)
	3) Local Power Range monitor	2.5% to 125% power (124)	2.5% to 125% power (172)	2.5% to 125% power (124)	2.5% to 125% power (124)
	4) Average Power Range Monitor	5% to 125% power (4)	5% to 125% power (4)**	5% to 125% power (4)	5% to 125% power (4)
	f. Number and Type of In-Core Neutron Sources	5-Sb-Be	7-Sb-Be	5-Sb-Be	5-Sb-Be
9.	Reactivity Control				
	a. Approximate Effective Reactivity of Core with all Control Rods in (cold)	0.96k	0.96k	0.96k	0.96k
	b. Effective Reactivity of Core with Strongest Control Rod out (cold)	<0.99k	<0.99k	<0.99k	<0.99k
	c. Typical Moderator Temperature Coefficient (°k/k F)*				

** *Brown's Ferry Units 2 and 3.*
* *Beginning of core life*

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	1) Cold (at 68°F)	-5.0×10^{-5}	-5.0×10^{-5}	-5.0×10^{-5}	-5.0×10^{-5}
	2) Hot (no voids)	-16.0×10^{-5}	-16.0×10^{-5}	-16.0×10^{-5}	-16.0×10^{-5}
	d. Typical Moderator Void Coefficient (k/k% void)*				
	1) Hot (no voids)	-0.9×10^{-3}	-0.9×10^{-3}	-0.9×10^{-3}	-0.9×10^{-3}
	2) At rated output	-1.05×10^{-3}	-1.05×10^{-3}	-1.05×10^{-3}	-1.05×10^{-3}
	e. Typical Fuel Temperature (Doppler) Coefficient*				
	1) Cold (at 68°F)	-0.94×10^{-5}	-0.94×10^{-5}	-0.94×10^{-5}	-0.94×10^{-5}
	2) Hot (no voids)	-0.97×10^{-5}	-0.97×10^{-5}	-0.97×10^{-5}	-0.97×10^{-5}
	3) At rated output	$\leq -0.83 \times 10^{-5}$	$\leq -0.83 \times 10^{-5}$	$\leq -0.83 \times 10^{-5}$	$\leq -0.83 \times 10^{-5}$

F. CONTAINMENT SYSTEMS

1.	Primary Containment				
	a. Type	Pressure Suppression	Pressure Suppression	Pressure Suppression	Pressure Suppression
	b. Construction				
	1) Drywell	Light Bulb/ Reinforced Concrete with steel liner	Light Bulb/ Steel Vessel	Light Bulb/ Steel Vessel	Light Bulb/ Steel Vessel
	2) Pressure Suppression Chamber	Torus/Reinforced Concrete with steel liner	Torus/Steel Vessel	Torus/Steel Vessel	Torus/Steel Vessel
	c. Pressure Suppression Chamber-Internal Design Pressure (psig)	+62	+56	+56	+56

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* *Beginning of core life*

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

	Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
d. Pressure Suppression Chamber-External Design Pressure (psi)	+2	+1	+2	+2
e. Drywell-Internal Design Pressure (psig)	+62	+56	+56	+56
f. Drywell-External Design Pressure (psi)	+2	+1	+2	+2
g. Drywell Free Volume (ft^3)	164,100	159,000	145,430	146,240
h. Pressure Suppression Chamber Free Volume (ft^3)	124,000	119,000	109,810	110,950
i. Pressure Suppression Pool Water Volume (ft^3)	87,600	85,000	87,660	87,660
j. Submergence of Vent Pipe Below Pressure Pool Surface (ft)	4	4	4	3 ft - 8 in.
k. Design Temperature of Drywell (°F)	300	281	281	281
l. Design Temperature of Pressure Suppression Chamber (°F)	220	281	281	281
m. Downcomer Vent Pressure Loss Factor	6.21	6.21	6.21	6.21
n. Break Area/Gross Vent Area	0.02	0.019	0.019	0.019
o. Drywell Free Volume/Pressure Suppression Chamber Free Volume	1.32	1.33	1.4	1.3
p. Calculated Maximum Drywell Pressure after blowdown with no prepurge (psig)	49.4	40	46	46.5

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	q. Leakage Rate (Percent Free Volume per Day)	0.5	0.5	0.5	1.2
2.	Secondary Containment				
	a. Type	Controlled Leakage, Elevated Release	Controlled Leakage, Elevated Release	Controlled Leakage, Elevated Release	Controlled Leakage, Elevated Release
	b. Construction				
	1) Lower Levels	Reinforced Concrete	Reinforced Concrete	Reinforced Concrete	Reinforced Concrete
	2) Upper Levels	Steel Superstructure and Siding	Steel Superstructure and Siding	Steel Superstructure and Siding	Steel Superstructure and Siding
	3) Roof	Metal Decking with Built-up Roofing	Steel Sheeting	Steel Sheeting	Steel Sheeting
	c. Internal Design Pressure (psig)	0.25	0.25	0.25	0.25
	b. Design Inleakage Rate (Percent free volume/day at 0.25 in. H_2O	100	100	100	100
3.	Elevated Release Point				
	a. Type	Stack	Stack	Stack	Stack
	b. Construction	Reinforced Concrete	Steel	Steel	Reinforced Concrete
	c. Height (above ground)	100 Meters	200 Meters	100 Meters	150 Meters

G. PLANT AUXILIARY SYSTEMS

1.	Emergency Core Cooling Systems (number)				
	a. Reactor Core Spray Cooling System	2 Loops	2 Loops	2 Loops	2 Loops

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	b. Reactor Core High Pressure Coolant Injection System	1 pump	1 pump	1 pump	1 pump
	c. Auto-Relief System)	1	1	1	1
	d. Reactor Core Residual Heat Removal System				
	1) Low Pressure Coolant Injection Subsystem	4 pumps	4 pumps	4 pumps	4 pumps
	2) Primary Containment Spray/Cooling Subsystem	1	1	1	1
	3) Reactor Shutdown Cooling Subsystem	1	1	1	1
2.	Reactor Auxiliary System (number)				
	a. Spent Fuel Pool Cooling and Demineralizing System	1	1	1	1
	b. Reactor Cleanup Demineralizer System	1	1	1	1
	c. Reactor Core Isolation Cooling System	1	1	1	1

H. PLANT ELECTRICAL POWER SYSTEMS

1.	Transmission System				
	Outgoing Lines (number-rating)	8-230 kV	4-500 kV	4-345 kV	5-230 kV
2.	Auxiliary Power Systems				
	a. Incoming Lines (number-rating)	8-230 kV	2-161 kV	1-69 kV 1-115 kV	5-230 kV

TABLE 1-3 Nuclear Plant Principal Plant Design Features Comparison [Historical]

		Brunswick Units 1 & 2	Brown's Ferry Units 1, 2 & 3	Cooper	Edwin I. Hatch Nuclear Plant Unit-1
	b. Onsite sources				
	1) Auxiliary Transformers	2	2	1	2
	2) Startup Transformers	2	2	1	2
	3) Shutdown Transformers	0	0	1	0
3.	Standby Diesel Generator System				
	Number of Diesel Generators	4	3 of 4	4	3

Table 1.7.1

Comparison of Nuclear System Design Characteristics

(Parameters are related to rated power output for a single unit unless otherwise noted. Values given apply to the originally licensed design).

Thermal and Hydraulic Design	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Rated Power, MWt	1593	3293	2436	1670
Design power, MWt	1665	3440	2537	1670
Steam flow rate, lb/hr	6.43×10^6	13.38×10^6	10.03×10^6	6.77×10^6
Core coolant flow rate, lb/hr	48.0×10^6	102.5×10^6	75.5×10^6	57.6×10^6
Feedwater flow rate, lb/hr	6.40×10^6	13.33×10^6	10.445×10^6	6.77×10^6
Feedwater temperature, °F	372	376.1	387.4	376.3
System pressure, nominal in steam dome, psia	1020	1020	1020	1020
Average power density, kw/liter	50.94	50.8	51.2	40.6
Maximum thermal output, kw/ft	18.37	18.35	18.3	17.5
Average thermal output, kw/ft	7.079	7.049	7.114	5.7
Maximum heat flux, Btu/hr-ft^2	425,500	425,048	428,308	405,000
Average heat flux, Btu/hr-ft^2	163,926	163,230	164,734	131,350
Maximum UO_2 temperature, °F	4380	4380	4380	2750
Average volumetric fuel temperature, °F	1100	1100	1100	900
Average fuel rod surface temperature, °F	558	558	558	558
Minimum critical heat flux ratio (MCHFR)	$\geq$1.9	$\geq$1.9	$\geq$1.9	$\geq$1.9
Coolant enthalpy at core inlet, Btu/lb	519.8	521.3	526.2	523.0
Core maximum exit voids within assemblies	74.7	79	79	
Core average exit quality, % steam	13.3	13.2	13.9	12.1
Design Power Peaking Factor				
Maximum relative assembly power	1.4	1.4	1.4	1.58
Local peaking factor	1.24	1.24	1.24	1.24
Axial peaking factor	1.5	1.5	1.5	1.57
Total peaking factor	2.60	2.6	2.6	3.08
Nuclear Design (First Core)				
Water/UO_2 volume ratio (cold)	2.47	2.41	2.41	2.42
Thermal and Hydraulic Design				
Reactivity with strongest control rod out, k_{eff}	<0.99	<0.99	<0.99	<0.99
Moderator temperature coefficient				
At 68°F, $\Delta k/k$ - °F water	-5.0×10^{-5}	-5.0×10^{-5}	-5.0×10^{-5}	-8.9×10^{-5}
Hot, no voids, $\Delta k/k$ - °F water	-39.0×10^{-5}	-39.0×10^{-5}	-39.0×10^{-5}	-17.0×10^{-5}

Table 1.7.1
(Continued)

	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Moderator void coefficient				
Hot, no voids, Δk/k - % void	-1.0×10^{-3}	-1.0×10^{-3}	-1.0×10^{-3}	-1.0×10^{-3}
At rated output, Δk/k - % void	-1.6×10^{-3}	-1.6×10^{-3}	-1.6×10^{-3}	-1.4×10^{-3}
Fuel temperature doppler coefficient				
At 68°F, Δk/k - °F fuel	-1.3×10^{-5}	-1.3×10^{-5}	-1.3×10^{-5}	-1.2×10^{-5}
Hot, no voids, Δk/k - °F fuel	-1.2×10^{-5}	-1.2×10^{-5}	-1.2×10^{-5}	-1.2×10^{-5}
At rated output, Δk/k - °F fuel	-1.3×10^{-5}	-1.3×10^{-5}	-1.3×10^{-5}	$\leq -1.2 \times 10^{-5}$
Initial average U-235 enrichment, W/O	2.50%	2.19%	2.23%	$\geq$2.25%
Fuel average discharge exposure, MWD/ton	19,085	19,000	19,000	19,000
Core Mechancial Design				
Fuel Assembly				
Number of fuel assemblies	368	764	560	484
Fuel rod array	7 x 7	7 x 7	7 x 7	7 x 7
Overall dimensions, inches	175.83	175.88	175.88	175.88
Weight of UO_2 per assembly, pounds	Undished - 490.53 Dished (3%) - 479.35	Undished - 490.35 Dished (3%) - 483.42	Undished - 490.35 Dished - 483.42	Undished - 492.5 Dished - 481.7
Weight of fuel assembly, pounds	Undished - 682.33 Dished (3%) - 671.05	Undished - 681.48 Dished (3%) - 674.55	Undished - 681.48 Dished - 674.55	Undished - 678.9 Dished - 668
Fuel Rods				
Number per fuel assembly	49	49	49	49
Outside diameter, inch	0.563	0.563	0.562	0.563
Clad thickness, inch	0.032	0.032	0.032	0.032
Gap - pellet to clad, inch	0.006	0.0055	0.005	0.005
Length of gas plenum, inches	16	16	16	11.24
Clad material	Zircaloy-2	Zircaloy-2	Zircaloy-2	Zircaloy-2 and/or -4
Cladding process	Free standing loaded tubes	Free standing loaded tubes	Free standing loaded tubes	Free standing loaded tubes
Fuel Pellets				
Material	Uranium dioxide	Uranium dioxide	Uranium dioxide	Uranium dioxide
Density, % of theoretical	95%	93%	93%	93%
Diameter, inch	0.487	0.488	0.488	0.488
Length, inch	0.5	0.5	0.5	0.5

Table 1.7.1
(Continued)

	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Fuel Channel				
Overall dimension, inches (length)	166.875	166.875	166.875	166.875
Thickness, inch	0.08	0.08	0.08	0.08
Cross section dimensions, inches	5.438 x 5.438	5.438 x 5.438	5.438 x 5.438	5.438 x 5.438
Material	Zircaloy-4	Zircaloy-4	Zircaloy-4	Zircaloy-4
Core Assembly				
Fuel weight as UO_2, pounds	178,145	370,933	272,849	238,370
Zirconium weight, pounds (Z-2 + Z-4 Spacers)	63,539	131,000	96,370	80,990
Core diameter (equivalent), inches	129.9	187.1	160.2	149
Core height (active fuel), inches	144	144	144	144
Core Mechanical Design				
Reactor Control System				
Number of movable control rods	89	185	137	121
Shape of movable control rods	Cruciform	Cruciform	Cruciform	Cruciform
Pitch of movable control rods	12.0	12.0	12.0	12.0
Control material in movable rods	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes
Type of control rod drives	Bottom entry, locking piston	Bottom entry, locking piston	Bottom entry, locking piston	Bottom entry, locking piston
Number of temporary control curtains	156	372	248	216
Curtain material	Flat, boron--stainless steel	Flat, boron--stainless steel	Flat, boron--stainless steel	Flat, boron--stainless steel
Method of variation of reactor power	Movable control rods and variable coolant pumping	Movable control rods and variable coolant pumping	Movable control rods and variable coolant pumping	Movable control rods and variable coolant pumping
Reactor Vessel Design				
Material		Carbon steel-clad		
Design pressure, psia	1265	1265	1265	1265
Design temperature, °F	575	575	575	575
Inside diameter ft-in.	17 - 2	20 - 11	18 - 2	17 - 2
Inside height, ft-in.	63 - 1.5	72 - 11 1/8	69 - 4	63 - 2
Side thickness (including clad)	5.187	6.313	5.531	5.187
Minimum clad thickness, inches	1/8	1/8	1/8	1/8

Table 1.7.1
(Continued)

	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Reactor Coolant Recirculation Design				
Number of recirculation loops	2	2	2	2
Design pressure				
Inlet leg, psig	1175	1148	1148	1148
Outlet leg, psig	1274	1326	1274	1248
Design temperature, °F	562	562	562	562
Pipe diameter, inches	28	28	28	28
Pipe material	304/316	304/316	304/316	304
Recirculation pump flow rate, GPM	32,500	45,200	45,200	32,500
Number of jet pumps in reactor	20	20	20	20
Main Steam Lines				
Number of steam lines	4	4	4	4
Design pressure, psig	1146	1146	1146	1146
Design temperature, °F	563	563	563	563
Pipe diameter, inches	18	26	24	18
Pipe material	Carbon Steel (ASTM A155 KC70 or ASTM A106 Grade B)			
In-Core Neutron Instrumentation				
Number of in-core neutron detectors (fixed)	80	172	124	96
Number of in-core detector assemblies	20	43	31	24
Number of detectors per assembly	4	4	4	4
Number of traversing-incore-probe neutron detectors	3	5	4	3
Range (and number) of detectors				
Source range monitoring subsystem	Source to .001% power (4)	Source to .001% power (4)	Source to .001% power (4)	Source to .001% power (4)
Intermediate range monitoring subsystem	.0002% to 20% power (6)	.0001% to 10% power (8)	.0001% to 10% power (8)	.0001% to 10% power (8)
Local power range monitoring subsystem	0.1% to 125% power (80)	5% to 125% power (172)	5% to 125% power (124)	5% to 125% power (96)
Average power range monitoring subsystem	2.5% to 125% power (6)	2.5% to 125% power (6)	2.5% to 125% power (6)	5% to 125% power (6)
Number and type of in-core neutron sources	4 Sb-Be	7 Sb-Be	5 Sb-Be	5 Sb-Be
Core Standby Cooling System (These systems are sized on design power.)				
Core Spray System				
Number of loops	2	2	2	2
Flow rate (gpm)	3000 at 120 psid	6250 at 122 psid	4625 at 120 psid	3020 at 307 psid

Table 1.7.1
(Continued)

	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
High Pressure Coolant Injection System (No.)	1	1	1	1
Number of loops	1	1	1	1
Flow rate (gpm)	4250	5000	4250	3000
Automatic Depressurization System (No.)	1	1	1	1
Low Pressure Coolant Injection (No.)	1	1	1	1
Number of pumps	4	4	4	4
Flow rate (gpm/pump)	7,200 at 20 psid	10,000 at 20 psid	7,700 at 20 psid	4,000 at 20 psid
Auxiliary Systems				
Residual Heat Removal System				
Reactor shutdown cooling (number of pumps)	4	4	4	4
Flow rate (gpm/pump) (1)	7,200	10,000	7,700	4,000
Capacity (Btu/hr/heat exchanger) (2)	57.5×10^6	70×10^6	32×10^6	24.5×10^6
Number of heat exchangers	2	4	2	2
Primary containment cooling				
Flow rate (gpm)	28,000	40,000	30,800	16,000
RHR Service Water System				
Flow rate (gpm/pump)	2,700	4,500	8,000	3,500
Number of pumps	4	8	4	4
Reactor Core Isolation Cooling System				
Flow rate (gpm/pump)	400	616 at 1120 psid	400 at 1120 psid	400
Fuel Pool Cooling and Cleanup System				
Capacity (Btu/hr)	2.37×10^6	8.8×10^6	3.3×10^6	2.87×10^6

(1) Capacity during reactor flooding made with 3 of 4 pumps running.
(2) Capacity during post-accident cooling mode with 165°F shell side inlet temperature, maximum service water temperature, and 1 RHR pump and 1 RHR service water pump in operation.

TABLE 1.7.2

Comparison of Power Conversion System Design Characteristics
(Values given apply to the originally licensed design.)

Turbine-Generator	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Design power, MWt	1665	3440	2537	1670
Design power, MWe	564	1152	849	543
Generator speed, RPM	1800	1800	1800	1800
Design steam flow, lb/hr	6.721×10^6	14.049×10^6	10.48×10^6	
Turbine inlet pressure, psig	950	965	970	950
Turbine Bypass System				
Capacity, percent of turbine design steam flow	105	25	25	15
Main Condenser				
Heat removal capacity, Btu/hr	3605×10^6	7770×10^6	5800×10^6	3750×10^6
Circulating Water System				
Number of pumps	3	3	3	2
Flow rate, gpm/pump	122,000	200,000	185,000	140,000
Condensate and Feedwater Systems				
Design flow rate, lb/hr	6.4×10^6	13.999×10^6	10.096×10^6	6.77×10^6
Number of condensate pumps	3	3	3	2
Number of condensate booster pumps	-	3	-	-
Number feedwater pumps	3	3	2	2
Condensate pump drive	ac power	ac power	ac power	ac power
Condensate booster pump drive	-	ac power	-	-
Feedwater pump drive	ac power	turbine	turbine	ac power

TABLE 1.7.3

Comparison of Electrical Power Systems Design Characteristics

(Values given apply to the originally licensed design.)

Transmission System	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Outgoing lines (number-rating)	2-345 kV 2-115 kV	6-500 kV	2-230 kV	2-345 kV 3-115 kV 2-230 kV
Normal Auxiliary AC Power				
Incoming lines (number-rating)	2-345 kV 2-115 kV 1-4160 V	2-161 kV	2-30 kV	1-345 kV 1-115 kV
Auxiliary transformers	1	3	1	2
Startup transformers	1	2	2	1
Standby AC Power Supply				
Number diesel generators	2	4	3	2
Number of 4160 V standby busses	2	4	3	4
Number of 480 V standby busses	2	8	4 (600 V)	4
DC Power Supply				
Number of 125 V or 250 V batteries	2	4	2	2-125 V 1-250 V
Number of 125 V or 250 V busses	3	4	4	2-125 V 1-250 V

TABLE 1.7.4

Comparison of Containment Design Characteristics
(Values given apply to the original licensed design.)

Primary Containment*	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Type	Pressure suppression	Pressure suppression	Pressure suppression	Pressure suppression
Construction				
Drywell	Light bulb shape; steel vessel	Light bulb shape; steel vessel	Light bulb shape; steel vessel	Light bulb shape; steel vessel
Pressure suppression chamber	Torus; steel vessel	Torus; steel vessel	Torus; steel vessel	Torus; steel vessel
Pressure Suppression Chamber				
Internal design pressure (psig)	56	56	56	56
External design pressure (psi)	2	2	2	2
Drywell-internal design pressure (psig)	56	56	56	56
Drywell-external design pressure (psi)	2	2	2	2
Drywell free volume (ft^3)	134,200	159,000	146,400	134,200
Pressure suppression chamber free volume (ft^3)	108,250	119,000	101,410	108,250
Pressure suppression pool water volume (ft^3)	77,970	135,000	86,660	77,970
Submergence of vent pipe below pressure pool surface (ft)	4	4	4	4
Design temperature of drywell (°F)	281	281	281	281
Design temperature of pressure suppression chamber (°F)	281	281	281	281

*Where applicable, containment parameters are based on design power.

TABLE 1.7.4
(Continued)

Primary Containment*	Vermont Yankee	Browns Ferry Each Unit	Hatch Station	Monticello
Downcomer vent pressure loss factor	6.21	6.21	6.21	6.21
Break area/Total vent area	0.019	0.019	0.019	0.019
Calculated maximum pressure after blowdown Drywell (psig)	35	46.6	45	41
Pressure suppression chamber (psig)	22	27	28	26
Initial pressure suppression pool temperature rise (°F)	35	50	50	50
Leakage rate (% free volume/day at 56 psig and 281°F)	0.5	0.5	0.5	0.5
Secondary Containment				
Type	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, elevated release
Construction				
Lower levels	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete
Upper levels	Steel superstructure and siding	Steel superstructure and siding	Steel superstructure and siding	Steel superstructure and siding
Roof	Steel sheeting	Steel sheeting	Steel sheeting	Built up on steel decking
Internal design pressure (psig)	0.25	0.25	0.25	0.25
Design in leakage rate (% free volume/day at 0.25 inches H_2O)	100	100	100	100
Elevated Release Point				
Type	Stack	Stack	Stack	Stack
Construction	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete
Height (above ground)	318 feet	600 feet	100 meters	238 feet

*Where applicable, containment parameters are based on design power.

TABLE 1.7.5

Comparison of Structural Design Characteristics
(Values given apply to the original licensed design.)

Seismic Design	Vermont Yankee	Browns Ferry Nuclear Plant	Hatch Station	Monticello
Design earthquate (horizontal g)	0.07	0.10	0.08	0.06
Maximum earthquake (horizontal g)	0.14	0.20	0.15	0.12
Wind Design				
Maximum sustained (mph)	80	100	105	100
Tornadoes (mph)	300	300	300	300

TABLE 1.7.6

Comparison of Systems Design Characteristics

(Parameters are related to rated power output for a single unit unless otherwise noted.) (Values given apply to the originally licensed design.)

	Vermont Yankee	Dresden 2
Thermal and Hydraulic Design		
Rated power, MWt	1593	2255
Design power, MWt	1665	2527
Steam flow rate, lb/hr	6.43×10^6	9.945×10^6
Core coolant flow rate, lb/hr	48.0×10^6	98×10^6
Feedwater flow rate, lb/hr	6.40×10^6	9.94×10^6
Feedwater temperature, °F	372	348
System pressure, nominal in steam dome, psia	1020	1020
Average power density, kw/liter	50.94	41.08
Maximum thermal output, kw/ft	18.37	17.5
Average thermal output, kw/ft	7.079	5.7
Maximum heat flux, Btu/hr-ft^2	425,500	405,000
Average heat flux, Btu/hr-ft^2	163,926	131,860
Maximum UO_2 temperature, °F	4380	3470
Average volumetric fuel temperature, °F	1100	1050
Average fuel rod surface temperature, °F	558	558
Minimum critical heat flux ratio (MCHFR)	≥ 1.9	≥ 1.9
Coolant enthalpy at core inlet, Btu/lb	519.8	522.3
Core maximum exit voids within assemblies	74.7	76
Core average exit quality, % steam	13.3	10.1
Design Power Peak Factor		
Maximum relative assembly power	1.4	1.47
Local peaking factor	1.24	1.30
Axial peaking factor	1.5	1.57
Total peaking factor	2.60	3.60
Nuclear Design (First Core)		
Water/UO_2 volume ratio (cold)	2.47	2.41
Reactivity with strongest control rod out, k_{eff}	<0.99	<0.99
Moderator temperature coefficient		
At 68°F, $\Delta k/k$ - °F water	-5.0×10^{-5}	-8.0×10^{-5}
Hot, no voids, $\Delta k/k$ - °F water	-39.0×10^{-5}	-17.0×10^{-5}
Moderator void coefficient		
Hot, no voids, $\Delta k/k$ - % void	-1.0×10^{-3}	-1.0×10^{-3}

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
At rated output, $\Delta k/k$ - % void	-1.6×10^{-3}	-1.4×10^{-3}
Fuel temperature doppler coefficient		
At 68°F, $\Delta k/k$ - °F fuel	-1.3×10^{-5}	-1.2×10^{-5}
Hot, no voids, $\Delta k/k$ - °F fuel	-1.2×10^{-5}	-1.2×10^{-5}
At rated output, $\Delta k/k$ - % fuel	-1.3×10^{-5}	-1.2×10^{-5}
Initial average U-235 enrichment, W/O	2.50%	2.12%
Fuel average discharge exposure, MWD/ton	19,085	19,000
Core Mechanical Design		
Fuel Assembly		
Number of fuel assemblies	368	724
Fuel rod array	7 x 7	7 x 7
Overall dimensions, inches	175.88	175.88
Weight of UO_2 per assembly, pounds	Undished-490.53 Dished (3%)-479.35	Undished-492.5 Dished-481.7
Weight of fuel assembly, pounds	Undished-682.23 Dished (3%)-671.05	Undished-678.9 Dished-668.0
Fuel Rods		
Number per fuel assembly	49	49
Outside diameter, inch	0.563	0.563
Clad thickness, inch	0.032	0.032
Gap - pellet to clad, inch	0.005	0.005
Length of gas plenum, inches	16	11.24
Clad material	Zircaloy-2	Zircaloy-2
Cladding process	Free standing loaded tubes	Free standing loaded tubes
Fuel Pellets		
Material	Uranium dioxide	Uranium dioxide
Density, % of theoretical	95%	93%
Diameter, inch	0.487	0.488
Length, inch	0.5	0.5
Fuel Channel		
Overall dimension, inches (length)	166.875	166.875

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
Thickness, inch	0.080	0.080
Cross section dimensions, inches	5.438 x 5.438	5.438 x 5.438
Material	Zircaloy-4	Zircaloy-4
Core Assembly		
Fuel weight as UO_2, pounds	178,145	351,258
Zirconium weight, pounds (Z-2 + Z-4 Spacers)	63,539	121,154
Core diameter (equivalent), inches	129.9	182.2
Core height (active fuel), inches	144	144
Reactor Control System		
Method of variation of reactor power	Movable control rods and various coolant pumping	Moveable control rods and various coolant pumping
Number of movable control rods	89	177
Shape of movable control rods	Cruciform	Cruciform
Pitch of movable control rods	12.0	12.0
Control material in movable rods	B_4C granules compacted in SS tubes	B_4C granules compacted in SS tubes
Type of control rod drives	Bottom entry, locking piston	Bottom entry, locking piston
Number of temporary control curtains	156	340
Curtain material	Flat, boron--stainless steel	Flat, boron--stainless steel
Reactor Vessel Design		
Material	Carbon steel-clad	Carbon steel-clad
Design pressure, psia	1265	1265
Design temperature, °F	575	575
Inside diameter ft-in.	17 - 2	20 - 11
Inside height ft-in.	63 - 1.5	68 - 7 5/8
Side thickness (including clad)	5.187	6.125
Minimum clad thickness, inches	1/8	1/8
Reactor Coolant Recirculation Design		
Number of recirculation loops	2	2
Design pressure		
Inlet leg, psig	1175	1175

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
Outlet leg, psig	1274	1325
Design temperature, °F	562	565
Pipe diameter, inches	28	28
Pipe material	304/316	304/316
Recirculation pump flow rate, GPM	32,500	45,000
Number of jet pumps in reactor	20	20
Main Steam Lines		
Number of steam lines	4	4
Design pressure, psig	1146	1146
Design temperature, °F	563	563
Pipe diameter, inches	18	20
Pipe material	Carbon steel	Carbon steel
Core Standby Cooling Systems		
(These systems are sized on design power.)		
Core Spray System		
Number of loops	2	2
Flow rate (gpm)	3000 at 120 psid	4500 at 90 psid
Core Mechanical Design		
In-Core Neutron Instrumentation		
Number of in-core neutron detectors (fixed)	80	164
Number of in-core detector assemblies	20	41
Number of detectors per assembly	4	4
Number of traversing-incore-probe neutron detectors	3	3
Range (and number) of detectors Source range monitoring subsystem	Source to 0.001% power (4)	Source to 0.001% power (4)
Intermediate range monitoring subsystem	0.0002% to 20% power (6)	0.0003% to 10% power (8)
Local power range monitoring subsystem	0.01% to 125% power (80)	5% to 125% power (164)
Average power range monitoring subsystem	2.5% to 125% power (6)	5% to 125% power (6)
Number and type of in-core neutron sources	4 Sb-Be	7 Sb-Be
Core Standby Cooling Systems		
High pressure coolant injection system (No.)	1	1

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
Number of loops	1	1
Flow rate (gpm)	4250	5600
Automatic depressurization system (No.)	1	1
Low pressure coolant injection (No.)	1	1
Number of pumps	4	4
Flow rate (gpm/pump)	7200 at 20 psid	4833 at 20 psid
Auxiliary Systems		
Residual Heat Removal System		
Reactor shutdown cooling (number of pumps)	4	3[3]
Flow rate (gpm/pump)[1]	7,200	5,350[3]
Capacity (btu/hr/heat exchanger)[2]	57.5×10^6	27×10^6[3]
Number of heat exchangers	2	3[3]
Primary containment cooling		
Flow rate (gpm)	28,000	
RHR Service Water System		
Flow rate (gpm/pump)	2,700	3,500
Number of pumps	4	4
Reactor Core Isolation Cooling System		
Flow rate (gpm)	400	None
Fuel Pool Cooling and Cleanup System		
Capacity (Btu/hr)	2.37×10^6	3.65×10^6
Turbine-Generator		
Design power, MWt	1665	2527
Design power, MWe	564	809
Generator speed, RPM	1800	1800
Design steam flow, lb/hr	6.721×10^6	9.945×10^6
Turbine inlet pressure, psig	950	950
Turbine Bypass System		

(1) Capacity during reactor cooling mode with three of four pumps running.

(2) Capacity during post-accident cooling mode with 165°F shell side inlet temperature, maximum service water temperature, and one RHR pump and one RHR service water pump in operation.

(3) **Separate shutdown cooling system.**

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
Capacity, percent of turbine design steam flow	105	40
Main Condenser		
Heat removal capacity, Btu/hr	3605×10^6	
Circulating Water System		
Number of pumps	3	3
Flow rate, gpm/pump	122,000	
Condensate and Feedwater Systems		
Design flow rate, lb/hr	6.4×10^6	9.725×10^6
Number of condensate pumps	3	4
Number of condensate booster pumps		4
Number feedwater pumps	3	3
Condensate pump drive	ac power	ac power
Condensate booster pump drive		ac power
Feedwater pump drive	ac power	ac power
Transmission System		
Outgoing lines (number-rating)	2-345 kV 2-115 kV	5-345 kV
Normal Auxiliary AC Power		
Incoming lines (number-rating)	2-345 kV 2-115 kV 1-4160 V	5-345 kV 6-138 kV
Auxiliary transformers	1	1
Startup transformers	1	1
Standby AC Power Supply		
Number diesel generators	2	3 (for 2 units)
Number of 4160V standby busses	2	2
Number of 480V standby busses	2	2
DC Power Supply		
Number of 125 V or 250 V batteries	2	1-125 V 1-250 V
Number of 125 V or 250 V busses	3	2-125 V 2-250 V

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
Primary Containment*		
Type	Pressure suppression	Pressure suppression
Construction		
Drywell	Light bulb shape; steel vessel	Light bulb shape; steel vessel
Pressure suppression chamber	Torus; steel vessel	Torus; steel vessel
Pressure Suppression Chamber		
Internal design pressure (psig)	56	62
External design pressure (psi)	2	1
Drywell-internal design pressure (psig)	56	62
Drywell-external design pressure (psi)	2	2
Drywell free volume (ft^3)	134,200	158,236
Pressure suppression chamber free volume (ft^3)	108,250	117,245
Pressure suppression pool water volume (ft^3)	77,970	
Submergence of vent pipe below pressure pool surface (ft)	4	4
Design temperature of drywell (°F)	281	281
Design temperature of pressure suppression chamber (°F)	281	281
Downcomer vent pressure loss factor	6.21	6.21
Break area total vent area (ft^2)	0.019	0.019
Calculated maximum pressure after blowdown drywell (psig)	35	48
Pressure suppression chamber (psig)	22	28
Initial pressure suppression pool temperature rise (°F)	35	50
Leakage rate (% free volume/day at 56 psig and 281°F)	0.5	0.5 (at 62 psig and 281°F)

*Where applicable, containment parameters are based on design power.

TABLE 1.7.6

(Continued)

	Vermont Yankee	Dresden 2
Secondary Containment		
Type	Controlled leakage elevated release	Controlled leakage elevated release
Construction		
Lower levels	Reinforced concrete	Reinforced concrete
Upper levels	Steel super-structure and siding	Steel super-structure and siding
Roof	Steel sheeting	Concrete slabs
Initial design pressure (psig)	0.25	0.25
Design in leakage rate (% free volume/day at 0.25 inches H_2O)	100	100
Elevated Release Point		
Type	Stack	Stack
Construction	Reinforced concrete	Reinforced concrete
Height (above ground)	318 feet	310 feet
Seismic Design		
Design earthquake (horizontal g)	0.07	0.10
Maximum earthquake (horizontal g)	0.14	0.20
Wind Design		
Maximum sustained (mph)	80	110
Tornadoes (mph)	300	300

NUREG-0800
(Formerly NUREG-75/087)

U.S. NUCLEAR REGULATORY COMMISSION

STANDARD REVIEW PLAN

OFFICE OF NUCLEAR REACTOR REGULATION

14.2.1 GENERIC GUIDELINES FOR EXTENDED POWER UPRATE TESTING PROGRAMS

This Standard Review Plan (SRP) section provides general guidelines for reviewing proposed extended power uprate (EPU) testing programs. This review ensures that the proposed testing program adequately verifies that the plant can be operated safely at the proposed uprated power level.

Power uprates can be classified in three categories. Measurement uncertainty recapture power uprates are less than 2 percent and are achieved by implementing enhanced techniques for calculating reactor power. Stretch power uprates are typically up to 7 percent and do not generally involve major plant modifications. EPUs are greater than stretch power uprates and have been approved for increases as high as 20 percent. EPUs usually require significant modifications to major balance-of-plant equipment. A power uprate is classified as an EPU based on a combination of the proposed power increase and the plant modifications necessary to support the requested uprate. This SRP applies only to EPU license amendment requests.

<u>REVIEW RESPONSIBILITIES</u>

Primary - Equipment and Human Performance Branch (IEHB)
Secondary - Reactor Systems Branch (SRXB)
Plant Systems Branch (SPLB)
Probabilistic Safety Assessment Branch (SPSB)
Materials and Chemical Engineering Branch (EMCB)
Electrical and Instrumentation & Controls Branch (EEIB)
Mechanical & Civil Engineering Branch (EMEB)

I. AREAS OF REVIEW

The Equipment and Human Performance Branch coordinates the review of the overall power uprate testing program. Secondary review branches are responsible for reviewing EPU applications to ensure that the licensee has proposed an EPU testing program that demonstrates that structures, systems, and components (SSCs) will perform satisfactorily in service at the requested increased plant power level. Secondary review branches will assist IEHB in the review of proposed testing plans and acceptance criteria, as needed. The review of EPU testing programs should be performed in conjunction with staff reviews of other aspects of the EPU license amendment request.

II. ACCEPTANCE CRITERIA

Extended power uprate test program acceptance criteria are based on meeting the relevant requirements of the following regulations:

- Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, establishes in Criterion 1, "Quality Standards and Records," as it relates to establishing the necessary testing requirements for SSCs important to safety, such that there is reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. However, as discussed in Section 2.1.5.6 of LIC-100, "Control of Licensing Basis for Operating Reactors," the General Design Criteria (GDC) are not applicable to plants with construction permits issued before May 21, 1971. Each plant licensed before the GDC were formally adopted was evaluated on a plant-specific basis, determined to be safe, and licensed by the Commission.

- Criterion XI, "Test Control," of Appendix B to10 CFR Part 50, as it relates to establishment of a test program to assure that testing required to demonstrate that SSCs will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents.

- 10 CFR 50.90, "Application for Amendment of License or Construction Permit," as it relates to an application for an amendment following as far as applicable the form prescribed for original applications. Section 50.34, "Contents of Applications: Technical Information," which specifies requirements for the original operating license application, requires that the Final Safety Analysis Report (FSAR) include plans for preoperational testing and initial operations.

Technical Rationale

This review ensures that the proposed EPU testing program adequately demonstrates that SSCs will perform satisfactorily at EPU conditions. In particular, the EPU test program provides assurance that (1) any power-uprate related modifications to the facility have been adequately constructed and implemented; and (2) the facility can be operated at the proposed EPU conditions in accordance with design requirements and in a manner that will not endanger the health and safety of the public.

The following paragraphs describe the technical rationale for application of the above acceptance criteria to the review of EPU test programs:

- Criterion I of Appendix A to 10 CFR Part 50, establishes the necessary testing requirements for SSCs important to safety; that is, SSCs that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. Also, SSCs important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability. Additionally, a quality assurance program shall be established to ensure that SSCs will satisfactorily perform their safety functions.

Application of Criterion 1 of 10 CFR 50, Appendix A, to the EPU test program ensures that the requested power uprate does not invalidate original testing requirements contained in the original licensing basis. This ensures that SSCs continue to meet their original design specifications. Testing is performed, as necessary to provide assurance that SSCs continue to meet their design capabilities. For example, testing could be performed to demonstrate that SSCs functions, as expected, actuate in the intended time period and produce the expected flow rate within the expected time period. Original quality assurance standards and applicable codes and standards would be satisfied. The quality assurance program ensures proper documentation and traceability that applicable testing was accomplished, and codes and standards satisfied.

- Criterion XI of Appendix B to 10 CFR Part 50 requires that a test program be established to assure that all testing required to demonstrate that SSCs will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test program requirements include, as appropriate, proof tests prior to installation, preoperational tests, and operational tests of SSCs. Test procedures are required to include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. Test results are required to be documented and evaluated to assure that test requirements have been satisfied.

  Application of Criterion XI of 10 CFR Part 50, Appendix B, to the EPU test program ensures that SSC capabilities to perform specified functions are not adversely impacted by increasing the maximum allowed power level. This also ensures that deficiencies are identified and corrected, and that testing activities are conducted in a manner which minimizes operational reliance on untested safety functions. This provides a high degree of assurance of SSC and overall plant readiness for safe operation within the bounds of the design and safety analyses, assurance against unexpected or unanalyzed plant behavior, and assurance against early safety function failures in service. Regulatory Guide (RG) 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," Revision 2, describes the general scope and depth of initial test programs that the NRC staff found acceptable during the review of original operating license applications. The SSCs subject to initial testing performed safety functions that included fission product containment; reactivity monitoring and control; reactor safe shutdown (including maintaining safe shutdown); core cooling; accident prevention; and consequence mitigation as specified in the design and credited in safety analyses.

- 10 CFR 50.90, "Application for Amendment of License or Construction Permit," requires that each licensee submitting a license amendment request fully describe the changes desired and follow, as far as practicable, the form prescribed for the original application. Section 50.34, "Contents of Applications: Technical Information," specifies requirements for the original operating license application. In particular, 10 CFR 50.34(b)(6)(iii) requires that each application for a license to operate a facility include in the FSAR plans for preoperational testing and initial operations. The initial test program (which includes preoperational testing and testing during initial operation) verifies that SSCs are capable of performing their safety functions as specified in the design and credited in safety analyses.

Application of 10 CFR 50.90 and 10 CFR 50.34(b)(6)(iii) to the EPU test program ensures that the licensee submits adequate information, commitments, and plans demonstrating that operation at the requested higher power level will be within the bounds of the design and safety analyses and that EPU testing activities will be conducted in a sequence and manner which minimizes operational reliance on untested SSCs or safety functions. This also ensures that preoperational and initial startup testing invalidated by the requested increase in power level are evaluated and reperformed as necessary to demonstrate safe operation of the plant.

III. REVIEW PROCEDURES

The purpose of this review is to ensure that the proposed EPU testing program adequately controls the initial power ascension to the requested EPU power level. The EPU test program shall include sufficient steady-state and transient performance testing to demonstrate that SSCs will perform satisfactorily at the requested power level. The proposed EPU test program should be based on a systematic review of the initial plant test program to identify initial licensing power-ascension testing that may be invalidated by the requested EPU. Additionally, the EPU test program should include sufficient testing to demonstrate that EPU-related plant modifications have been adequately implemented.

A. Comparison of Proposed EPU Test Program to the Initial Plant Test Program

1. General Discussion

The licensee should provide a comparison of the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison shall include (1) all power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level; and (2) initial power-ascension tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either reperform initial power-ascension tests within the scope of this comparison or adequately justify proposed deviations.

2. Specific Acceptance Criteria

Within its associated technical discipline, each secondary branch reviewer will determine if the licensee has adequately identified the following in the EPU license amendment request:

- All power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level.
- All initial power-ascension tests performed at power levels lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU.
- Differences between the proposed EPU power-ascension test program and the portions of the initial power-ascension program included within the scope of this comparison.

The reviewer should refer to the plant-specific testing identified in FSAR Chapter 14.2, "Initial Plant Test Program" (or the equivalent FSAR section for non standard format plants), and startup test reports, if available, to verify that the licensee has adequately identified the scope of the initial plant test program. Additionally, Attachment 1, "Steady-State Power Ascension Testing Applicable to Extended Power Uprates," and Attachment 2, "Transient Testing Applicable to Extended Power Uprates," to this SRP section provide a generic summary of power-ascension tests performed at or near full power.

If the licensee's proposed EPU test program does not include performance of testing originally performed during the initial plant test program, the reviewer shall ensure that the licensee adequately justifies all differences. The reviewer should refer to Section III.C, below, for guidance on assessing the adequacy of justifications for proposed differences.

B. <u>Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications</u>

1. <u>General Discussion</u>

EPUs usually require significant modifications to major balance-of-plant equipment, in addition to setpoint and operating parameter changes. Therefore, within its respective technical area, each secondary review branch will assess if the licensee adequately evaluated the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to anticipated initiating events. The objective of this review is to verify that the licensee has proposed a testing program which demonstrates that EPU-related modifications to the facility have been adequately implemented.

The reviewer is not expected to evaluate the specific component- and system-level testing requirements for each plant modification, parameter change, or setpoint adjustment. Based on previous experience, testing required by Technical Specifications and existing 10 CFR Part 50, Appendix B, quality assurance programs have been adequate to demonstrate individual system or component performance characteristics. Therefore, this review is intended to ensure that functions important to safety that rely on the integrated operation of multiple SSCs following an anticipated operational occurrence are adequately demonstrated prior to extended operation at the requested EPU power level.

2. <u>Specific Acceptance Criteria</u>

Based on review of the licensee's EPU license amendment request, the reviewer will determine if the licensee has adequately identified the following:

- plant modifications and setpoint adjustments necessary to support operation at power uprate conditions, and

- changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions.

The reviewer should assess if the licensee adequately identified functions important to safety that are affected by EPU-related modifications, setpoint adjustments, and changes in plant operating parameters. In particular, the licensee should have considered the safety impact of first-of-a-kind plant modifications, the introduction of new system dependencies or interactions, and changes in system response to initiating events. The review scope can be limited to those functions important to safety associated with the anticipated operational occurrences described in Attachment 2 to this SRP, "Transient Testing Applicable to Extended Power Uprates." To assist in this review, Attachment 2 also includes typical transient testing acceptance criteria and functions important to safety associated with these anticipated events.

The reviewer should verify that the proposed EPU test program adequately demonstrates each function important to safety that meets all of the following criteria: (1) is impacted by EPU-related modifications, (2) is required to mitigate a plant transient listed in Attachment 2, and (3) involves the integrated response of multiple SSCs. If a function important to safety cannot be adequately tested by overlapping individual component- or system-level tests, the licensee should propose suitable system functional testing.

C. <u>Use of Evaluation To Justify Elimination of Power-Ascension Tests</u>

1. <u>General Discussion</u>

In certain cases, the licensee may propose an EPU test program that does not include all of the power-ascension testing that would normally be required by the review criteria of Sections III.A and III.B above. The licensee shall provide an adequate justification for each of these normally required power-ascension tests that are not included in the EPU test program. For each proposed test exception within its technical area, each secondary review branch will verify the adequacy of the licensee's justification.

2. <u>Specific Acceptance Criteria</u>

If the licensee proposes to not perform a power-ascension test that would normally be required by the review criteria contained in Sections III.A and III.B, above, the reviewer should ensure that the licensee provides an adequate justification. The proposed EPU test program shall be sufficient to adequately demonstrate that SSCs will perform satisfactorily in service. The reviewer should consider the following factors when assessing the adequacy of the licensee's justification:

a. Previous Operating Experience

If the licensee proposes not to perform a required transient test based on operating experience, a review should be conducted to determine the applicability of the operating experience to the specific plant configuration and test requirements. If the licensee references industry operating experience, the reviewer should consider similarity in plant design and equipment; operating power level; and operating and emergency operating procedures.

b. Introduction of New Thermal-Hydraulic Phenomena or Identified System Interactions

The reviewer should ensure that the licensee adequately addressed the effects of any new thermal-hydraulic phenomena or system interactions that may be introduced as a result of the EPU.

c. Facility Conformance to Limitations Associated With Analytical Analysis Methods

The licensee's justification for not performing specific power-ascension testing should include consideration of the facility conformance to limitations associated with analytical analysis methods. These limitations may include, but are not limited to, plant operating parameters, system configuration, and power level.

d. Plant Staff Familiarization With Facility Operation and Trial Use of Operating and Emergency Operating Procedures

Plant modifications and parameter changes, in conjunction with increased decay heat generation associated with higher power operation, can impact the execution of abnormal and emergency operating procedures. For example, the EPU may change the timing and sequence of significant operator actions used in abnormal and emergency operating procedures, or could impact accident mitigation strategies in abnormal or emergency operating procedures.

For each EPU license amendment request, IEHB reviews the impact of the requested power uprate on operator training and human factors in accordance with separate EPU review standard guidance. These reviews include an evaluation of the changes in operator actions, procedures, and training (including necessary changes to the control room simulator) resulting from the EPU. Although the initial power-ascension test program objectives, as described in Reference 8, included plant staff familiarization with facility operation and trial use of plant abnormal and emergency operating procedures, the EPU review standard adequately addresses the operator training and human factors aspects of the EPU. Therefore, it is not expected that power-ascension testing would normally be required for the purposes of procedure verification or operator familiarization.

e. <u>Margin Reduction in Safety Analysis Results for Anticipated Operational Occurrences</u>

The licensee's justification for not performing a particular power-ascension test should include a consideration of the change in the associated safety analysis results due to the proposed EPU. To aid in this review, the information provided in Attachment 2 to this SRP section includes a reference to the safety analysis SRP sections related to each transient test, if applicable. For safety analysis acceptance criteria that can be quantitatively measured (e.g. peak reactor coolant system pressure), a reduction in available margin by less than approximately 10 percent would normally be considered to be a minimal change in consequences. The available margin is the difference between the standard review plan accident analysis acceptance criterion of interest and the plant-specific value calculated at EPU conditions. For larger reductions in available margin, the licensee may consider such factors as the amount of remaining margin; the sensitivity of the results to changes in analysis assumptions; and the capability of transient testing to provide useful confirmatory data.

Although the initial power-ascension test program objectives, as described in Reference 8, included validation of analytical models and verification of assumptions used for predicting plant response to anticipated transients and postulated accidents, transient testing is not required for the purposes of analytical code validation for EPU license amendment reviews. The applicability and validation of accident analysis analytical codes is reviewed by the staff in accordance with separate EPU review standard guidance.

f. <u>Guidance Contained in Vendor Topical Reports</u>

The NRC previously reviewed and accepted General Electric (GE) Company Licensing Topical Report, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (referred to as ELTR-1), NEDC-32424P-A, Class III, February 1999, as an acceptable basis for BWR EPU amendment requests. This topical report provided specific guidance for the performance of integrated system transient testing at EPU conditions. As described in Section 5.11.9.d and Appendix L.2.4 of ELTR-1, the generator load rejection and the main steam isolation valve (MSIV) tests verify that the plant performance is as predicted and projected from previous test data.

For PWRs, Westinghouse Report WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Plant," provides limited guidance for power uprate testing. Specifically, the document states that the recommended test program for the nuclear steam supply system and interfacing balance-of-plant systems be developed on a plant-specific basis depending on the magnitude of hardware modifications and the magnitude of the power uprate.

Although the NRC has previously approved certain exceptions to power-ascension testing requirements, the reviewer should assess the licensee's proposed justifications on a plant-specific basis.

g. Risk Implications

For cases where the licensee proposes a risk-informed basis for not performing certain transient tests, SPSB should be consulted to assist in the review. Risk-informed justifications for not performing transient tests should be carefully weighed against the potential benefits of performing the testing. In addition to the risks inherent in initiating a plant transient, the review should also consider the benefit of identifying potential latent equipment deficiencies or other plant problems under controlled circumstances during transient testing. In any case, a risk-informed justification should not be used as the sole basis for not performing transient testing.

If the licensee provides adequate justification for not performing certain power-ascension tests, the staff may conclude that the EPU test program is acceptable without the performance of these tests.

D. Evaluate the Adequacy of Proposed Transient Testing Plans

1. General Discussion

The EPU amendment request should include plans for the initial approach to the increased EPU power level and steady-state testing that will be used to verify that the reactor plant operates within design parameters.

2. Specific Acceptance Criteria

For each EPU power-ascension test proposed by the licensee to demonstrate that the plant can be safely operated at EPU conditions, the staff will review the test objectives, summary of prerequisites and test methods, and specific acceptance criteria for each test to establish that the functional adequacy of SSCs is verified. This review assures that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the licensing basis for the facility.

Each secondary review branch will review the licensee's plans for the EPU test program within its respective technical area. The licensee's EPU test program should include the following:

- The initial approach to the uprated EPU power level should be performed in an incremental manner and include steady-state power hold points to evaluate plant performance above the original full-power level.

- The licensee should propose appropriate testing and acceptance criteria that ensure that the plant responds within design predictions. The predicted responses should be developed using real or expected values of items such as beginning-of-life core reactivity coefficients, flow rates, pressures, temperatures, and response times of equipment and the actual status of the plant, and not the values or plant conditions used for conservative evaluations of postulated accidents.

- Contingency plans should be implemented if the predicted plant response is not obtained.

- The test program should be scheduled and sequenced to minimize the time untested functions important to safety are relied upon during operation above the original licensed full-power level. Safety-related functions relied upon during operation shall be verified to be operable in accordance with existing Technical Specification and Quality Assurance Program requirements.

To assist this review, Attachments 1 and 2 to this SRP section provide a generic listing of full power steady-state and transient tests and related acceptance criteria that are potentially applicable to an EPU test program.

If a power-ascension test is required to demonstrate that the plant can be operated safely at EPU conditions, the reviewer shall determine if a license condition should be imposed to ensure that this testing is performed in a timely and controlled manner.

IV. EVALUATION FINDINGS

When the review of the information in the EPU amendment application is complete and the reviewer has determined that it is satisfactory and in accordance with the acceptance criteria in Section II above, a statement similar to the following should be provided in the staff's Safety Evaluation Report (SER):

"The staff has reviewed the EPU test program information provided in the license amendment request in accordance with SRP Section 14.2.1 and relevant guidance provided in the EPU Review Standard. This review included an evaluation of (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, (2) transient testing requirements necessary to demonstrate that the plant can be operated safely at the proposed increased maximum licensed thermal power level, and (3) the test program's conformance with applicable regulations. The staff finds that there is reasonable assurance that the applicant's EPU testing program satisfies the requirements of Criterion XI, 'Test Control,' of 10 CFR Part 50, Appendix B, and is therefore acceptable."

V. IMPLEMENTATION

This SRP section will be used by the staff when performing safety evaluations of EPU license amendment applications submitted pursuant to 10 CFR 50.90. This SRP is not intended to be used in place of plant-specific licensing bases to assess the acceptability of an EPU application. Applicability of this SRP is determined on a plant-specific basis consistent with the licensing basis of the plant.

In addition, where the NRC has approved a specific methodology (e.g., topical report) for the type of power uprate being requested, licensees should follow the format prescribed for that specific methodology and provide the information called for in that methodology and the NRC's letter and safety evaluation approving the methodology. Except in those cases in which the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described herein will be used by the staff in its evaluation of conformance with Commission regulations.

VI. REFERENCES

1. 10 CFR Part 52, §52.47 "Contents of Applications."

2. 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

3. NUREG-1503, "Final Safety Evaluation Report Related to the Certification of the Advanced Boiling Water Reactor," Volumes 1 and 2, July 1994.

4. SECY-01-0124, "Power Uprate Application Reviews," dated July 9, 2001. The related Staff Requirements Memorandum is dated May 24, 2001.

5. General Electric Company Licensing Topical Report, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (ELTR-1), NEDC-32424P-A, Class III, February 1999.

6. General Electric Company Licensing Topical Report, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR-2), NEDC-32523P-A, Class III, February 2000, and Supplement 1, Volumes I and II.

7. General Electric Company Licensing Topical Report, "Constant Pressure Power Uprate," NEDC-33004P, Revision 1, July 2001.

8. NRC Regulatory Guide 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," Revision 2, August 1978.

9. NRR Office Instruction LIC-100, "Control of Licensing Basis for Operating Reactors."

10. NRR Office Instruction LIC-101, "License Amendment Review Procedures."

11. NRR Office Instruction LIC-500, "Processing Requests for Reviews of Topical Reports."

12. Westinghouse WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," January 1983.

13. NRC Inspection Manual, Part 9900, "10 CFR Part 50.59, Changes, Tests and Experiments," Change Notice Number 01-008.

14. NRC Information Notice 2002-26, "Failure of Steam Dryer Cover Plate After a Recent Power Uprate," September 11, 2002.

Steady-State Power Ascension Testing Applicable to Extended Power Uprates

Power Ascension Test	Reference	Recommended Initial Conditions	Typical Test Acceptance Criteria	Primary Technical Review Branch
Conduct vibration testing and monitoring of reactor vessel internals and reactor coolant system components	Regulatory Guide (RG) 1 68, App A 4.s, 5.9	lowest practical power level	reactor vessel and reactor coolant system component vibration characteristics within design See NRC Information Notice 2002-26 and RG 1 20	EMEB
Measure power reactivity coefficients (PWR) or power vs flow characteristics (BWR)	RG 1 68, App A 5.a	100% of RTP	characteristics in accordance with design	SRXB
Steady-state core performance	RG 1 68, App A 5 b	100% of RTP	characteristics in accordance with design	SRXB
Control rod patterns exchange	RG 1 68, App A 5 c	power equal to highest power level that rod exchanges will be allowed at power	core limits not exceeded	SRXB
Control rod misalignment testing	RG 1 68, App A 5 i	100% of RTP rod misalignment equal to or less than TS limits	demonstrate ability to detect misalignment	SRXB
Failed fuel detection system	RG 1 68, App A 5 q	100% of RTP	verify proper operation	IEHB
Plant process computer	RG 1.68, App A 5 r	100% of RTP	inputs and calculation are correct	SPLB/EEIB
Calibrate major or principal plant control systems	RG 1.68, App A 5.s	100% of RTP	verify performance	SRXB/SPLB
Main steam and main feedwater system operation	RG 1.68, App A 5 v	100% of RTP	operate in accordance with design performance requirements	SPLB
Shield and penetration cooling systems	RG 1 68, App A 5.w	100% of RTP	maintain temperature within design limits	SPLB
ESF auxiliary and environmental systems	RG 1.68, App A 5 x	100% of RTP	capable of performing design functions	SPLB
Calibrate systems used to determine reactor thermal power	RG 1 68, App A 5 y	100% of RTP	verify performance	EEIB
Chemical and radiochemical control systems	RG 1 68, App A 5.a.a	100% of RTP	control systems function in accordance with design	IEHB
Sample reactor coolant system and secondary coolant systems	RG 1 68, App A 5.a.a	100% of RTP	chemistry limits are not exceeded	EMCB

Power Ascension Test	Reference	Recommended Initial Conditions	Typical Test Acceptance Criteria	Primary Technical Review Branch
Radiation surveys	RG 1.68, App A : 5 b b	100% of RTP	shielding adequacy and identify 10 CFR Part 20 high-radiation zones	IEHB
Ventilation systems (including primary containment and steam line tunnel)	RG 1 68, App A 4 j and 5 f f	100% of RTP	maintain service areas within design limits	SPLB
Acceptability of reactor internals, piping, and component movement, vibrations, and expansions	RG 1 68, App A 1.a.1, 1.a 3, 1 e , and 5 o o	Lowest practical power level	parameters within design values	EMEB

Transient Testing Applicable to Extended Power Uprates

Transient Test	Reference	Typical Reactor Plant Initial Conditions	Typical Transient Test Acceptance Criteria and Associated Functions Important to Safety	Applicable Accident Analyses (SRP Section)
Relief valve testing	RG 1 68, App A 4 p and 5 t Inspection Procedure (IP) 72510	Reactor power level at predetermined power level plateaus All relief valves set in auto Individual valve functional tests at prescribed power level plateaus Individual valve capacity tests at low power (25% of RTP) using bypass valve movement or turbine generator output as a measurement variable	Relief valve rating at a specified pressure setting Delay time between the signal initiating relief valve opening and the start of motion Opening stroke time of the main valve disc and distance Closing stroke time of the main valve piston following release of the pneumatically operated mechanical push rod	15.1.2 Inadvertent Opening of a Steam Generator Relief or Safety Valve 15 6.1 Inadvertent Opening of a PWR Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve
Dynamic response of plant to design load swings	RG 1 68, App A 5.h.h	100% of RTP	Performance in accordance with design	
Reactor core isolation cooling functional test	IP 72512	Steady-state reactor operations at rated temperature and pressure RCIC aligned for standby operation Reactor power at approximately 25% of RTP	Startup from hot standby conditions and discharge of rated flow into the reactor vessel at rated pressure and temperature within a specified time Verification of maximum rated flow isolation trip Verification of overspeed trip Turbine gland seal condenser system shall prevent steam leak to atmosphere	
Dynamic response of plant to limiting reactor coolant pump trips or closure of reactor coolant system flow control valves (Reactor coolant recirculation pump trip test)	RG 1 68, App A 5 l l IP 72512	100% of RTP Trip from steady-state power operation Recording of transients following trip and during pump restart Recording of limiting heat transfer parameters Return to two-pump operation in accord with facility operating procedures Trip of a single pump and of both pumps simultaneously.	Performance in accordance with design Instrumentation is adjusted to provide an accurate conversion of individual jet pump Δp values to a summed core flow over the range of two-pump operations Recirculation pump instrumentation is calibrated Loop flow from single-tap and double-tap pumps agrees within 3% Core flow from single-tap and double-tap pumps agrees within 2% Individual jet pump flow variation from average pump flow is limited	15 3 1 (BWR) & 15 3 2 (PWR) Loss of Forced Reactor Coolant Flow Including Trip of Pump Motor
Dynamic response of the plant to loss of feedwater heaters that results in most severe feedwater temperature reduction	RG 1.68, App A 5 k k	90% of RTP	performance in accordance with design	15.1.1 Decrease in Feedwater Temperature

Transient Test	Reference	Typical Reactor Plant Initial Conditions	Typical Transient Test Acceptance Criteria and Associated Functions Important to Safety	Applicable Accident Analyses (SRP Section)	
Dynamic response of plant to loss of feedwater flow	RG 1 68, Appendix A, Section 5 (Introduction)		plant performance in accordance with design	15 2.7	Loss of Normal Feedwater Flow
Dynamic response of plant for full load rejection (Loss of Offsite Power Testing)	RG 1.68, App A 5 n n IP 72517 IP 72582	100% of RTP with electrical system aligned for normal full-power operation and load rejection method should subject turbine to maximum credible overspeed condition steady-state plant operations with greater than 10% generator output (IP 72517 & 72582). trip of the plant with breakers in specified positions so that plant loads will be transferred directly to the diesel generators following loss of house power recirculation system flow control mode specified	Performance in accordance with design, including: Automatic transfer of plant loads as designed, automatic start of diesel generators, automatic load of diesel generators in the specified sequence Reactor pressure remains below the first safety valve setting Pressurizer safety valves do not lift All safety systems such as RPS, HPCI, diesel generators, and RCIC function without manual assistance Normal reactor cooling systems should maintain adequate core temperatures, and prevent actuation of the Automatic Depressurization System; however selected relief valves may function to control pressure Turbine bypass system operates to maintain specified pressure value Steam system power-actuated pressure relief valves open and close at specified value Pressurizer spray valves open and close at specified values. Reactor coolant temperature/pressure relationship remains within prescribed values Pressurizer level is maintained within prescribed limits Steam generator level remains within prescribed limits	15.2.6	Loss of Nonemergency AC Power to the Station Auxiliaries

Transient Test	Reference	Typical Reactor Plant Initial Conditions	Typical Transient Test Acceptance Criteria and Associated Functions Important to Safety	Applicable Accident Analyses (SRP Section)
Dynamic response of plant to turbine trip (Turbine trip or generator trip)	RG 1 68, App A 5 1 1 IP 72580 IP 72514	trip from steady state operation at greater than 95% of RTP initiation of the test by trip of the main generator output breaker recirculation system flow control mode must be specified	Performance in accordance with design, including reactor coolant pumps do not trip pressurizer spray valve opens and closes at the specified values reactor pressure remains below the setpoint of the first safety valves, pressurizer safety valves do not lift or weep pressurizer level within prescribed limits steam system power actuated pressure relief valve opens and closes at specified values reactor coolant pressure/temperature relationship remains within defined values steam generator level remains within prescribed limits, no flooding of the steam lines during the transient, no initiation of ECCS and MSIV isolation during the transient turbine bypass system operates to maintain specific pressure (plants with 100% bypass capability shall remain at power without scram during the transient) plants with select-rod-insertion shall maintain power without scram from recirculation pump overspeed or cold feedwater effect reactor protection system functions should be verified all safety and ECCS systems such as RPS, HPCI, diesel generators, and RCIC function without manual assistance if called upon normal reactor cooling systems should maintain adequate cooling and prevent actuation of automatic depressurization system, even though relief valves may function to control pressure plant electrical loads (transferred as designed) turbine overspeed criteria met	15 2.1 Turbine Trip
Dynamic response of plant to automatic closure of all main steam isolation valves	RG 1 68, App A 5 m,m IP 72510	Initial power level of 100% of RTP	performance in accordance with design acceptance criteria include MSIV closing time	15.2.4 Main Steam Isolation Valve Closure (BWR)

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11. ABSTRACT *(200 words or less)*

This Standard Review Plan (SRP) section provides general guidelines for reviewing proposed extended power uprate (EPU) testing programs. This review ensures that the proposed testing program adequately verifies that the plant can be operated safely at the proposed uprated power level.

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Attachment 7

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263

Extended Power Uprate

Justification for Exception to Large Transient Testing

JUSTIFICATION FOR EXCEPTION TO LARGE TRANSIENT TESTING

Background

The basis for the Constant Pressure Power Uprate (CPPU) request was prepared following the guidelines contained in the NRC approved, General Electric (GE) Company Licensing Topical Report for Constant Pressure Power Uprate (CLTR) Safety Analysis: NEDC-33004P-A Rev. 4, July 2003. The NRC staff did not accept GEs proposal for the generic elimination of large transient testing (i.e., Main Steam Isolation Valve (MSIV) closure and turbine generator load rejection) presented in NEDC-33004P Rev. 3. Therefore, on a plant specific basis, Vermont Yankee Nuclear Power Station (VYNPS) is taking exception to the large transient tests; MSIV closure and turbine generator load rejection.

The CPPU methodology, maintaining a constant pressure, simplifies the analyses and plant changes required to achieve uprated conditions. Although no plants have implemented an Extended Power Uprate (EPU) using the CLTR, thirteen plants have implemented EPUs without increasing reactor pressure.

- Hatch Units 1 and 2 (105% to 113% of Original Licensed Thermal Power (OLTP))
- Monticello (106% OLTP)
- Muehleberg (i.e., KKM) (105% to 116% OLTP)
- Leibstadt (i.e., KKL) (105% to 117% OLTP)
- Duane Arnold (105% to 120% OLTP)
- Brunswick Units 1 and 2 (105% to 120% OLTP)
- Quad Cities Units 1 and 2 (100% to 117% OLTP)
- Dresden Units 2 and 3 (100% to 117% OLTP)
- Clinton (100% to 120%)

Data collected from testing responses to unplanned transients for Hatch Units 1 and 2 and KKL plants has shown that plant response has consistently been within expected parameters.

Entergy believes that additional MSIV closure and generator load rejection tests are not necessary. If performed, these tests would not confirm any new or significant aspect of performance that is not routinely demonstrated by component level testing. This is further supported by industry experience which has demonstrated plant performance, as predicted, under EPU conditions. VYNPS has experienced generator load rejections from 100% current licensed thermal power (see VYNPS Licensee Event Reports (LER) 91-005, 91-009, and 91-014). No significant anomalies were seen in the plant's response to these events. Further testing is not necessary to demonstrate safe operation of the plant at CPPU conditions. A Scram from high power level results in an unnecessary and undesirable transient cycle on the primary system. In addition, the risk posed by intentionally initiating a MSIV closure transient or a generator load rejection, although small, should not be incurred unnecessarily.

VYNPS Response to Unplanned Transients:

VYNPS experienced an unplanned Generator Load Rejection from 100% power on 04/23/91. The event included a loss of off site power. A reactor scram occurred as a result of a Generator/Turbine trip on generator load reject due to the receipt of a 345 KV breaker failure signal. This was reported to the NRC in LER 91-009, dated 05/23/91. No significant anomalies were seen in the plant's response to this event. VYNPS also experienced the following unplanned generator load rejection events:

- On 3/13/91 with reactor power at 100% a reactor scram occurred as a result of turbine trip on generator load reject due to a 345KV Switchyard Tie Line Differential Fault. This event was reported to the NRC in LER 91-005, dated 4/12/91.
- On 6/15/91 during normal operation with reactor power at 100% a reactor scram occurred due to a Turbine Control Valve Fast Closure on Generator Load Reject resulting from a loss of the 345KV North Switchyard bus. This event was reported to the NRC in LER 91-014, dated 7/15/91.

No significant anomalies were seen in the plant's response to these events. Transient experience at high powers and for a wide range of power levels at operating BWR plants has shown a close correlation of the plant transient data to the predicated response.

Based on the similarity of plants, past transient testing, past analyses, and the evaluation of test results, the effects of the CPPU RTP level can be analytically determined on a plant specific basis. The transient analysis performed for the VYNPS CPPU demonstrates that all safety criteria are met and that this uprate does not cause any previous non-limiting events to become limiting. No safety related systems were significantly modified for the CPPU, however some instrument setpoints were changed. The instrument setpoints that were changed do not contribute to the response to large transient events. No physical modification or setpoint changes were made to the SRVs. No new systems or features were installed for mitigation of rapid pressurization anticipated operational occurrences for this CPPU. A Scram from high power level results in an unnecessary and undesirable transient cycle on the primary system. Therefore, additional transient testing involving scram from high power levels is not justifiable. Should any future large transients occur, VYNPS procedures require verification that the actual plant response is in accordance with the predicted response. Existing plant event data recorders are capable of acquiring the necessary data to confirm the actual versus expected response.

Further, the important nuclear characteristics required for transient analysis are confirmed by the steady state physics testing. Transient mitigation capability is demonstrated by other equipment surveillance tests required by the Technical Specifications. In addition, the limiting transient analyses are included as part of the reload licensing analysis.

MSIV Closure Event

Closure of all MSIVs is an Abnormal Operational Transient as described in Chapter 14 of the VYNPS Updated Final Safety Analysis Report (UFSAR). The transient produced by the fast closure (3.0 seconds) of all main steam line isolation valves represents the most severe abnormal operational transient resulting in a nuclear system pressure rise when direct scrams are ignored. The Code overpressure protection analysis assumes the failure of the direct isolation valve position scram. The MSIV closure transient, assuming the backup flux scram verses the valve position scram, is more significant. This case has been re-evaluated for CPPU with acceptable results.

The CLTR states that: "The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program." The original MSIV closure test allowed the scram to be initiated by the MSIV position switches.

As such, if the original MSIV closure test were re-performed, the results would be much less significant than the MSIV closure analysis performed by GE for CPPU.

The original MSIV closure test was intended to demonstrate the following:

1. *Determine reactor transient behavior during and following simultaneous full closure of all MSIVs.*

   Criteria:
   a) *Reactor pressure shall be maintained below 1230 psig.*
   b) *Maximum reactor pressure should be 35 psi below the first safety valve setpoint. (This is margin for safety valve weeping).*

2. *Functionally check the MSIVs for proper operation and determine MSIV closure time.*

   Criteria:
   a) *Closure time between 3 and 5 seconds.*

Item 1: Reactor Transient Behavior

For this event, the closure of the MSIVs cause a vessel pressure increase and an increase in reactivity. The negative reactivity of the scram from MSIV position switches should offset the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during the proposed MSIV closure test is much less limiting than any of the transients routinely re-evaluated. CPPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection system (RPS) logic is unaffected and with no steam dome pressure increase, overall control rod insertion times will not be significantly affected. MSIV closure speed is controlled by adjustments to the actuator and is considered very reliable as indicated below.

Reactor Pressure

Due to the minimal nature of the flux transient, the expected reactor pressure rise, Item 1 above, is largely dependent on SRV setpoint performance. At VYNPS all four SRVs are replaced with re-furbished and pre-tested valves each outage. After the outage, the removed valves are sent out for testing and recalibration for installation in the following outage. Over the past ten years there have been twenty five SRV tests performed. In those twenty five tests only one test found the as-found setting outside the Technical Specification (TS) current allowable tolerance of ±3%. This valve was found to deviate by 3.4% of its nominal lift setpoint. Note that this is bounded by the VYNPS design analysis for peak vessel pressure which assumes one of the four SRVs does not open at all (one SRV out of service). Given the historical performance of the VYNPS SRVs along with the design margins, performance of an actual MSIV closure test would provide little benefit for demonstrating vessel overpressure protection that is not already accomplished by the component level testing that is routinely performed, in accordance with the VYNPS TSs.

Because rated vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after a SRV lift. Since SRV leakage performance is considered acceptable at the current conditions, which match CPPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance should continue to be acceptable at CPPU conditions. An MSIV closure test would provide no significant additional confirmation of Item 1 performance criteria than the routine component testing performed every cycle, in accordance with the VYNPS TSs.

Item 2: MSIV Closure Time

Since steam flow assists MSIV closure, the focus of Item 2 was to verify that the steam flow from the reactor was not shut off faster than assumed (i.e., 3 seconds). During maintenance and surveillance, MSIV actuators are evaluated and adjusted as necessary to control closure speed, and VYNPS test performance has been good. To account for minor variations in stroke times, the calibration test procedure for MSIV closure (OP 5303) requires an as left fast closure time of 4.0 $\pm$0.2 seconds. The MSIVs were evaluated for CPPU. The evaluation included MSIV closure time and determined that the MSIVs are acceptable for CPPU operation. Industry experience, including VYNPS, has shown that there are no significant generic problems with actuator design. Confidence is very high that steam line closure would not be less than assumed by the analysis.

Other Plant Systems and Components Response

The MSIV limit switches that provide the scram signal are highly reliable devices that are suitable for all aspects of this application including environmental requirements. There is no direct effect by any CPPU changes on these switches. There may be an indirect impact caused by slightly higher ambient temperatures, but the increased temperatures will still be below the qualification temperature. These switches are expected to be equally reliable before and after CPPU.

The Reactor Protection System (RPS) and Control Rod Drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any CPPU changes. Minor changes in pressure drops across vessel components may result in very slight changes in control blade insertion rates. These changes have been evaluated and determined to be insignificant. The ability to meet the scram performance requirement is not affected by CPPU. Technical Specification (TS) requirements for these components will continue to be met.

CPPU Modifications

Feedwater System operation will require operation of all three feed pumps at CPPU conditions (unlike CLTP conditions). Operation of the additional Reactor Feed Pump (RFP) will not affect plant response to an MSIV closure transient. All feedwater pumps receive a trip signal prior to level reaching 177 inches. Overfill of the vessel after a trip would only occur if level exceeded approximately 235.5 inches. Since the feedwater pumps, the High Pressure Coolant Injection (HPCI) turbine, and the RCIC turbine all receive trip signals prior to level reaching 177 inches, a substantial margin exists. VYNPS operating history has demonstrated that this margin greatly exceeds vessel level overshoot during transient events. Based on this, there is adequate confidence that the vessel level will remain well below the main steam lines under CPPU conditions. The HPCI and RCIC pump trip functions are routinely verified as required by TSs and are considered very reliable.

The modification adding a recirculation pump runback following a RFP trip will not affect the plant response to this transient. The reactor scram signal from the MSIV limit switches will result in control rod insertion prior to any manual or automatic operation of the RFPs. Since control rods will already be inserted, a subsequent runback of the recirculation pumps will not affect the plant response.

The modification (BVY 03-23 "ARTS/MELLLA") to add an additional unpiped Spring Safety Valve (SSV) will not affect the plant response to this transient. The new third SSV will have the same lift setpoint as the two existing SSVs. This transient does not result in an opening of a SSV, nor is credit taken for SSV actuation.

Generator Load Reject Testing

"Generator Load Rejection From High Power Without Bypass" (GLRWB) is an Abnormal Operational Transient as described in Chapter 14 of the VYNPS Updated Final Safety Analysis Report (UFSAR). This transient competes with the turbine trip without bypass as the most limiting overpressurization transient that challenges thermal limits for each cycle. The GLRWB analysis assumes that the transient is initiated by a rapid closure of the turbine control valves. It also assumes that all bypass valves fail to open.

The CLTR states that: "The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program." The startup test for generator load reject allowed the select rod insert feature to reduce the reactor power level and, in conjunction with bypass valve opening, control the transient such that the reactor does not scram. Current VYNPS design does not include the select rod insert feature. The plant was also modified to include a scram from the acceleration relay of the turbine control system. Under current plant design, the original generator load reject test can not be re-performed. If a generator load reject with bypass test were performed, the results would be much less significant than the generator load reject without bypass closure analysis performed by GE for CPPU.

The original generator load reject test was intended to demonstrate the following:

1. *Determine and demonstrate reactor response to a generator trip, with particular attention to the rates of changes and peak values of power level, reactor steam pressure and turbine speed.*

   Criteria:
   a. *All test pressure transients must have maximum pressure values below 1230 psig*
   b. *Maximum reactor pressure should be 35 psi below the first safety valve setpoint. (This is margin for safety valve weeping).*
   c. *The select rod insert feature shall operate and in conjunction with proper bypass valve opening, shall control the transient such that the reactor does not scram.*

Due to plant modification discussed above, Criterion c. above would no longer be applicable for a generator load reject test. The generator load reject startup test was performed at 93.7% power; however, a reactor scram occurred during testing and invalidated the test. A design change to initiate an immediate scram on generator load reject was implemented and this startup test was subsequently cancelled since it was no longer applicable.

Item 1 Reactor Response

For a generator load reject with bypass event, given current plant design, the fast closure of the Turbine Control Valves (TCVs) cause a trip of the acceleration relay in the turbine control system. The acceleration relay trip initiates a full reactor scram. The bypass valves open, however, since the capacity of the bypass valves at CPPU is 87%, vessel pressure increases. This results in an increase in reactivity. The negative reactivity of the TCV fast closure scram from the acceleration relay should offset the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during a generator load rejection test would be much less limiting than any of the transients routinely re-evaluated. CPPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection system (RPS) logic is unaffected and with no steam dome pressure increase, overall control rod insertion times will not be significantly affected. A trip channel and alarm functional test of the turbine control valve fast closure scram is performed every three months in accordance with plant technical specifications. This trip function is considered very reliable.

Reactor Pressure

Due to the minimal nature of the flux transient, the expected reactor pressure rise, Criteria a. and b. above, are largely dependent on SRV setpoint performance. Refer to the MSIV closure Reactor Pressure section above for discussion of SRV setpoint performance.

Because rated vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after a SRV lift. Since SRV leakage performance is considered acceptable at the current conditions, which match CPPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance will continue to be acceptable at CPPU conditions. A generator load rejection test would provide no significant additional confirmation of performance criteria a. and b. than the routine component testing performed every cycle, in accordance with the VYNPS TSs.

Other Plant Systems and Components Response

The turbine control system acceleration relay hydraulic fluid pressure switches that provide the scram signal are highly reliable devices that are suitable for all aspects of this application including environmental requirements. There is no direct effect by any CPPU changes on these pressure switches. These switches are expected to be equally reliable before and after CPPU.

The Reactor Protection System (RPS) and Control Rod Drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any CPPU changes. Minor changes in pressure drops across vessel components may result in very slight changes in control blade insertion rates. These changes have been evaluated and determined to be insignificant. The ability to meet the scram performance requirement is not affected by CPPU. TS requirements for these components will continue to be met.

CPPU Modifications

As previously described, Feedwater System operation will require all three feed pumps at CPPU conditions. Operation of the additional Reactor Feed Pump (RFP) will not affect plant response to this transient. All feedwater pumps receive a trip signal prior to level reaching 177 inches.

Overfill of the vessel after a trip would only occur if level exceeded approximately 235.5 inches. Since the feedwater pumps, the High Pressure Coolant Injection (HPCI) turbine, and the RCIC turbine all receive trip signals prior to level reaching 177 inches, a substantial margin exists. VYNPS operating history has demonstrated that this margin greatly exceeds vessel level overshoot during transient events. Based on this, there is adequate confidence that the vessel level will remain well below the main steam lines under CPPU conditions. The HPCI and RCIC pump trip functions are routinely verified as required by TSs and are considered very reliable.

The modification adding a recirculation pump runback following a RFP trip will not affect the plant response to this transient. The reactor scram signal from turbine control valve fast closure will result in control blade insertion prior to any manual or automatic operation of the RFPs. Since control blades will already be inserted, a subsequent runback of the recirculation pumps will not affect the plant response.

The modification (BVY 03-23) "ARTS/MELLLA") to add an additional unpiped SSV will not affect the plant response to this transient. The new third SSV will have the same lift setpoint of the two existing SSVs. This transient does not result in an opening of a SSV nor is credit taken for SSV actuation.

HP Turbine modification replaces the steam flow path but will not affect the turbine control system hydraulic pressure switches that provide the turbine control valve fast closure scram signal to the RPS system.

Industry Boiling Water Reactor (BWR) Power Uprate Experience

Southern Nuclear Operating Company's (SNOC) application for EPU of Hatch Units 1 and 2 was granted without requirements to perform large transient testing. VYNPS and Hatch are both BWR/4 with Mark 1 containments. Although Hatch was not required to perform large transient testing, Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from 98% of uprated power in the summer of 1999. As noted in SNOC's LER 1999-005, no anomalies were seen in the plant's response to this event. In addition, Hatch Unit 1 has experienced one turbine trip and one generator load reject event subsequent to its uprate (i.e., LERs 2000-004 and 2001-002). Again, the behavior of the primary safety systems was as expected. No new plant behaviors were observed that would indicate that the analytical models being used are not capable of modeling plant behavior at EPU conditions.

The KKL power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 3138 MWt (i.e., 104.2% of OLTP) to 3515 MWt (i.e., 116.7% OLTP). Uprate testing was performed at 3327 MWt (i.e., 110.5% OLTP) in 1998, 3420 MWt (i.e., 113.5% OLTP) in 1999 and 3515 MWt in 2000.

KKL testing for major transients involved turbine trips at 110.5% OLTP and 113.5% OLTP and a generator load rejection test at 104.2% OLTP. The KKL turbine and generator trip testing demonstrated the performance of equipment that was modified in preparation for the higher power levels. Equipment that was not modified performed as before. The reactor vessel pressure was controlled at the same operating point for all of the uprated power conditions. No unexpected performance was observed except in the fine-tuning of the turbine bypass opening that was done as the series of tests progressed. These large transient tests at KKL demonstrated the response of the equipment and the reactor response. The close matches observed with predicted response provide additional confidence that the uprate licensing analyses consistently reflected the behavior of the plant.

Plant Modeling, Data Collection, and Analyses

From the power uprate experience discussed above, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about transient modeling or actual plant response. Since the VYNPS uprate does not involve reactor pressure changes, this experience is considered applicable.

The safety analyses performed for VYNPS used the NRC-approved ODYN transient modeling code. The NRC accepts this code for GE BWRs with a range of power levels and power densities that bound the requested power uprate for VYNPS. The ODYN code has been benchmarked against BWR test data and has incorporated industry experience gained from previous transient modeling codes. ODYN uses plant specific inputs and models all the essential physical phenomena for predicting integrated plant response to the analyzed transients. Thus, the ODYN code will accurately and/or conservatively predict the integrated plant response to these transients at CPPU power levels and no new information about transient modeling is expected to be gained from performing these large transient tests.

CONCLUSION

VYNPS believes that sufficient justification has been provided to demonstrate that an MSIV transient test and a generator load rejection test is not necessary or prudent. Also, the risk imposed by intentionally initiating large transient testing should not be incurred unnecessarily. As such, Entergy does not plan to perform additional large transient testing following the VYNPS CPPU.

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Docket No. 50-271
BVY 03-98

Attachment

Vermont Yankee Nuclear Power Station

Technical Specification Proposed Change No. 263

Supplement No. 3

Extended Power Uprate – Updated Information

Justification for Exception to Large Transient Testing

JUSTIFICATION FOR EXCEPTION TO LARGE TRANSIENT TESTING

Background

The basis for the Constant Pressure Power Uprate (CPPU) request was prepared following the guidelines contained in the NRC approved, General Electric (GE) Company Licensing Topical Report for Constant Pressure Power Uprate (CLTR) Safety Analysis: NEDC-33004P-A Rev. 4, July 2003. The NRC staff did not accept GEs proposal for the generic elimination of large transient testing (i.e., Main Steam Isolation Valve (MSIV) closure and turbine generator load rejection) presented in NEDC-33004P Rev. 3. Therefore, on a plant specific basis, Vermont Yankee Nuclear Power Station (VYNPS) is taking exception to performing the large transient tests; MSIV closure, turbine trip, and generator load rejection.

The CPPU methodology, maintaining a constant pressure, simplifies the analyses and plant changes required to achieve uprated conditions. Although no plants have implemented an Extended Power Uprate (EPU) using the CLTR, thirteen plants have implemented EPUs without increasing reactor pressure.

- Hatch Units 1 and 2 (105% to 113% of Original Licensed Thermal Power (OLTP))
- Monticello (106% OLTP)
- Muehleberg (i.e., KKM) (105% to 116% OLTP)
- Leibstadt (i.e., KKL) (105% to 117% OLTP)
- Duane Arnold (105% to 120% OLTP)
- Brunswick Units 1 and 2 (105% to 120% OLTP)
- Quad Cities Units 1 and 2 (100% to 117% OLTP)
- Dresden Units 2 and 3 (100% to 117% OLTP)
- Clinton (100% to 120%)

Data collected from testing responses to unplanned transients for Hatch Units 1 and 2 and KKL plants has shown that plant response has consistently been within expected parameters.

Entergy believes that additional MSIV closure, turbine trip, and generator load rejection tests are not necessary. If performed, these tests would not confirm any new or significant aspect of performance that is not routinely demonstrated by component level testing. This is further supported by industry experience which has demonstrated plant performance, as predicted, under EPU conditions. VYNPS has experienced generator load rejections from 100% current licensed thermal power (see VYNPS Licensee Event Reports (LER) 91-005, 91-009, and 91-014). No significant anomalies were seen in the plant's response to these events. Further testing is not necessary to demonstrate safe operation of the plant at CPPU conditions. A Scram from high power level results in an unnecessary and undesirable transient cycle on the primary system. In addition, the risk posed by intentionally initiating a MSIV closure transient, a turbine trip, or a generator load rejection, although small, should not be incurred unnecessarily.

VYNPS Response to Unplanned Transients:

VYNPS experienced an unplanned Generator Load Rejection from 100% power on 04/23/91. The event included a loss of off site power. A reactor scram occurred as a result of a turbine/generator trip on generator load rejection due to the receipt of a 345 KV breaker failure signal. This was reported to the NRC in LER 91-009, dated 05/23/91. No significant anomalies were seen in the plant's response to this event. VYNPS also experienced the following unplanned generator load rejection events:

- On 3/13/91 with reactor power at 100% a reactor scram occurred as a result of turbine/generator trip on generator load rejection due to a 345KV Switchyard Tie Line Differential Fault. This event was reported to the NRC in LER 91-005, dated 4/12/91.
- On 6/15/91 during normal operation with reactor power at 100% a reactor scram occurred due to a Turbine Control Valve Fast Closure on Generator Load Rejection resulting from a loss of the 345KV North Switchyard bus. This event was reported to the NRC in LER 91-014, dated 7/15/91.

No significant anomalies were seen in the plant's response to these events. Transient experience at high powers and for a wide range of power levels at operating BWR plants has shown a close correlation of the plant transient data to the predicated response.

Based on the similarity of plants, past transient testing, past analyses, and the evaluation of test results, the effects of the CPPU RTP level can be analytically determined on a plant specific basis. The transient analysis performed for the VYNPS CPPU demonstrates that all safety criteria are met and that this uprate does not cause any previous non-limiting events to become limiting. No safety related systems were significantly modified for the CPPU, however some instrument setpoints were changed. The instrument setpoints that were changed do not contribute to the response to large transient events. No physical modification or setpoint changes were made to the SRVs. No new systems or features were installed for mitigation of rapid pressurization anticipated operational occurrences for this CPPU. A Scram from high power level results in an unnecessary and undesirable transient cycle on the primary system. Therefore, additional transient testing involving scram from high power levels is not justifiable. Should any future large transients occur, VYNPS procedures require verification that the actual plant response is in accordance with the predicted response. Existing plant event data recorders are capable of acquiring the necessary data to confirm the actual versus expected response.

Further, the important nuclear characteristics required for transient analysis are confirmed by the steady state physics testing. Transient mitigation capability is demonstrated by other equipment surveillance tests required by the Technical Specifications. In addition, the limiting transient analyses are included as part of the reload licensing analysis.

MSIV Closure Event

Closure of all MSIVs is an Abnormal Operational Transient as described in Chapter 14 of the VYNPS Updated Final Safety Analysis Report (UFSAR). The transient produced by the fast closure (3.0 seconds) of all main steam line isolation valves represents the most severe abnormal operational transient resulting in a nuclear system pressure rise when direct scrams are ignored. The Code overpressure protection analysis assumes the failure of the direct isolation valve position scram. The MSIV closure transient, assuming the backup flux scram verses the valve position scram, is more significant. This case has been re-evaluated for CPPU with acceptable results.

The CLTR states that: "The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program." The original MSIV closure test allowed the scram to be initiated by the MSIV position switches. As such, if the original MSIV closure test were re-performed, the results would be much less significant than the MSIV closure analysis performed by GE for CPPU.

The original MSIV closure test was intended to demonstrate the following:

1. *Determine reactor transient behavior during and following simultaneous full closure of all MSIVs.*

   Criteria:
   a) Reactor pressure shall be maintained below 1230 psig.
   b) Maximum reactor pressure should be 35 psi below the first safety valve setpoint. (This is margin for safety valve weeping).

2. *Functionally check the MSIVs for proper operation and determine MSIV closure time.*

   Criteria:
   a) Closure time between 3 and 5 seconds.

Item 1: Reactor Transient Behavior

For this event, the closure of the MSIVs cause a vessel pressure increase and an increase in reactivity. The negative reactivity of the scram from MSIV position switches should offset the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during the proposed MSIV closure test is much less limiting than any of the transients routinely re-evaluated. CPPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection system (RPS) logic is unaffected and with no steam dome pressure increase, overall control rod insertion times will not be significantly affected. MSIV closure speed is controlled by adjustments to the actuator and is considered very reliable as indicated below.

Reactor Pressure

Due to the minimal nature of the flux transient, the expected reactor pressure rise, Item 1 above, is largely dependent on SRV setpoint performance. At VYNPS all four SRVs are replaced with re-furbished and pre-tested valves each outage. After the outage, the removed valves are sent out for testing and recalibration for installation in the following outage. Over the past ten years there have been twenty five SRV tests performed. In those twenty five tests only one test found the as-found setting outside the Technical Specification (TS) current allowable tolerance of ±3%. This valve was found to deviate by 3.4% of its nominal lift setpoint. Note that this is bounded by the VYNPS design analysis for peak vessel pressure which assumes one of the four SRVs does not open at all (one SRV out of service). Given the historical performance of the VYNPS SRVs along with the design margins, performance of an actual MSIV closure test would provide little benefit for demonstrating vessel overpressure protection that is not already accomplished by the component level testing that is routinely performed, in accordance with the VYNPS TSs.

Because rated vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after a SRV lift. Since SRV leakage performance is considered acceptable at the current conditions, which match CPPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance should continue to be acceptable at CPPU conditions. An MSIV closure test would provide no significant additional confirmation of Item 1 performance criteria than the routine component testing performed every cycle, in accordance with the VYNPS TSs.

Item 2: MSIV Closure Time

Since steam flow assists MSIV closure, the focus of Item 2 was to verify that the steam flow from the reactor was not shut off faster than assumed (i.e., 3 seconds). During maintenance and surveillance, MSIV actuators are evaluated and adjusted as necessary to control closure speed, and VYNPS test performance has been good. To account for minor variations in stroke times, the calibration test procedure for MSIV closure (OP 5303) requires an as left fast closure time of 4.0 $\pm$0.2 seconds. The MSIVs were evaluated for CPPU. The evaluation included MSIV closure time and determined that the MSIVs are acceptable for CPPU operation. Industry experience, including VYNPS, has shown that there are no significant generic problems with actuator design. Confidence is very high that steam line closure would not be less than assumed by the analysis.

Other Plant Systems and Components Response

The MSIV limit switches that provide the scram signal are highly reliable devices that are suitable for all aspects of this application including environmental requirements. There is no direct effect by any CPPU changes on these switches. There may be an indirect impact caused by slightly higher ambient temperatures, but the increased temperatures will still be below the qualification temperature. These switches are expected to be equally reliable before and after CPPU.

The Reactor Protection System (RPS) and Control Rod Drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any CPPU changes. Minor changes in pressure drops across vessel components may result in very slight changes in control blade insertion rates. These changes have been evaluated and determined to be insignificant. The ability to meet the scram performance requirement is not affected by CPPU. Technical Specification (TS) requirements for these components will continue to be met.

CPPU Modifications

Feedwater System operation will require operation of all three feed pumps at CPPU conditions (unlike CLTP conditions). Operation of the additional Reactor Feed Pump (RFP) will not affect ~~plant response to an MSIV closure transient. All feedwater pumps receive a trip signal prior to~~ level reaching 177 inches. Overfill of the vessel after a trip would only occur if level exceeded approximately 235.5 inches. Since the feedwater pumps, the High Pressure Coolant Injection (HPCI) turbine, and the Reactor Core Isolation Cooling (RCIC) turbine all receive trip signals prior to level reaching 177 inches, a substantial margin exists. VYNPS operating history has demonstrated that this margin greatly exceeds vessel level overshoot during transient events. Based on this, there is adequate confidence that the vessel level will remain well below the main steam lines under CPPU conditions. The HPCI and RCIC pump trip functions are routinely verified as required by TSs and are considered very reliable.

The modification adding a recirculation pump runback following a RFP trip will not affect the plant response to this transient. The reactor scram signal from the MSIV limit switches will result in control rod insertion prior to any manual or automatic operation of the RFPs. Since control rods will already be inserted, a subsequent runback of the recirculation pumps will not affect the plant response.

The modification (BVY 03-23 "ARTS/MELLLA") to add an additional unpiped Spring Safety Valve (SSV) will not affect the plant response to this transient. The new third SSV will have the same lift setpoint as the two existing SSVs. This transient does not result in an opening of a SSV, nor is credit taken for SSV actuation.

Generator Load Reject and Turbine Trip Testing

"Generator Load Rejection From High Power Without Bypass" (GLRWB) is an Abnormal Operational Transient as described in Chapter 14 of the VYNPS Updated Final Safety Analysis Report (UFSAR). This transient competes with the turbine trip without bypass as the most limiting overpressurization transient that challenges thermal limits for each cycle. The turbine trip and generator load reject are essentially interchangeable. The only differences are 1) whether the RPS signal originates from the acceleration relay (GLRWB) or from the main turbine stop valves (turbine trip), and 2) whether the control valves close shutting off steam to the turbine or the stop valves close to isolate steam to the turbine. Both tests would verify the same analytical model for plant response. Therefore, the GLRWB is considered bounding or equivalent to the Turbine Trip.

The GLRWB analysis assumes that the transient is initiated by a rapid closure of the turbine control valves. It also assumes that all bypass valves fail to open. The CLTR states that: "The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program." The startup test for generator load reject allowed the select rod insert feature to reduce the reactor power level and, in conjunction with bypass valve opening, control the transient such that the reactor does not scram. Current VYNPS design does not include the select rod insert feature. The plant was also modified to include a scram from the acceleration relay of the turbine control system. Under current plant design, the original generator load reject test can not be re-performed. If a generator load reject with bypass test were performed, the results would be much less significant than the generator load reject without bypass closure analysis performed for CPPU.

The original generator load reject test was intended to demonstrate the following:

1. *Determine and demonstrate reactor response to a generator trip, with particular attention to the rates of changes and peak values of power level, reactor steam pressure and turbine speed.*

Criteria:

a. *All test pressure transients must have maximum pressure values below 1230 psig*
b. *Maximum reactor pressure should be 35 psi below the first safety valve setpoint. (This is margin for safety valve weeping).*
c. *The select rod insert feature shall operate and in conjunction with proper bypass valve opening, shall control the transient such that the reactor does not scram.*

Due to plant modification discussed above, criterion c. above would no longer be applicable for a generator load reject test. The generator load reject startup test was performed at 93.7% power; however, a reactor scram occurred during testing and invalidated the test. A design change to initiate an immediate scram on generator load reject was implemented and this startup test was subsequently cancelled since it was no longer applicable.

Item 1 Reactor Response

For a generator load reject with bypass event, given current plant design, the fast closure of the Turbine Control Valves (TCVs) cause a trip of the acceleration relay in the turbine control system. The acceleration relay trip initiates a full reactor scram. The bypass valves open, however, since the capacity of the bypass valves at CPPU is 87%, vessel pressure increases. This results in an increase in reactivity. The negative reactivity of the TCV fast closure scram from the acceleration relay should offset the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during a generator load rejection test would be much less limiting than any of the transients routinely re-evaluated. CPPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection system (RPS) logic is unaffected and with no steam dome pressure increase, overall control rod insertion times will not be significantly affected. A trip channel and alarm functional test of the turbine control valve fast closure scram is performed every three months in accordance with plant technical specifications. This trip function is considered very reliable.

Reactor Pressure

Due to the minimal nature of the flux transient, the expected reactor pressure rise, Criteria a. and b. above, are largely dependent on SRV setpoint performance. Refer to the MSIV closure Reactor Pressure section above for discussion of SRV setpoint performance.

Because rated vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after a SRV lift. Since SRV leakage performance is considered acceptable at the current conditions, which match CPPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance will continue to be acceptable at CPPU conditions. A generator load rejection test would provide no significant additional confirmation of performance criteria a. and b. than the routine component testing performed every cycle, in accordance with the VYNPS TSs.

Other Plant Systems and Components Response

The turbine control system acceleration relay hydraulic fluid pressure switches that provide the scram signal are highly reliable devices that are suitable for all aspects of this application including environmental requirements. There is no direct effect by any CPPU changes on these pressure switches. These switches are expected to be equally reliable before and after CPPU.

The Reactor Protection System (RPS) and Control Rod Drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any CPPU changes. Minor changes in pressure drops across vessel components may result in very slight changes in control blade insertion rates. These changes have been evaluated and determined to be insignificant. The ability to meet the scram performance requirement is not affected by CPPU. TS requirements for these components will continue to be met.

CPPU Modifications

As previously described, Feedwater System operation will require all three feed pumps at CPPU conditions. Operation of the additional Reactor Feed Pump (RFP) will not affect plant response to this transient. All feedwater pumps receive a trip signal prior to level reaching 177 inches. Overfill of the vessel after a trip would only occur if level exceeded approximately 235.5 inches. Since the feedwater pumps, the High Pressure Coolant Injection (HPCI) turbine, and the RCIC turbine all receive trip signals prior to level reaching 177 inches, a substantial margin exists. VYNPS operating history has demonstrated that this margin greatly exceeds vessel level overshoot during transient events. Based on this, there is adequate confidence that the vessel level will remain well below the main steam lines under CPPU conditions. The HPCI and RCIC pump trip functions are routinely verified as required by TSs and are considered very reliable.

The modification adding a recirculation pump runback following a RFP trip will not affect the plant response to this transient. The reactor scram signal from turbine control valve fast closure will result in control blade insertion prior to any manual or automatic operation of the RFPs. Since control blades will already be inserted, a subsequent runback of the recirculation pumps will not affect the plant response.

The ARTS/MELLLA modification (BVY 03-23) to add an additional unpiped SSV will not affect the plant response to this transient. The new third SSV will have the same lift setpoint of the two existing SSVs. This transient does not result in an opening of a SSV nor is credit taken for SSV actuation.

HP Turbine modification replaces the steam flow path but will not affect the turbine control system hydraulic pressure switches that provide the turbine control valve fast closure scram signal to the RPS system.

Industry Boiling Water Reactor (BWR) Power Uprate Experience

Southern Nuclear Operating Company's (SNC) application for EPU of Hatch Units 1 and 2 was granted without requirements to perform large transient testing. VYNPS and Hatch are both BWR/4 with Mark 1 containments. Although Hatch was not required to perform large transient testing, Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from 98% of uprated power in the summer of 1999. As noted in SNOC's LER 1999-005, no anomalies were seen in the plant's response to this event. In addition, Hatch Unit 1 has experienced one turbine trip and one generator load reject event subsequent to its uprate (i.e., LERs 2000-004 and 2001-002). Again, the behavior of the primary safety systems was as expected. No new plant behaviors were observed that would indicate that the analytical models being used are not capable of modeling plant behavior at EPU conditions.

The KKL power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 3138 MWt (i.e., 104.2% of OLTP) to 3515 MWt (i.e., 116.7% OLTP). Uprate testing was performed at 3327 MWt (i.e., 110.5% OLTP) in 1998, 3420 MWt (i.e., 113.5% OLTP) in 1999 and 3515 MWt in 2000.

KKL testing for major transients involved turbine trips at 110.5% OLTP and 113.5% OLTP and a generator load rejection test at 104.2% OLTP. The KKL turbine and generator trip testing demonstrated the performance of equipment that was modified in preparation for the higher power levels. Equipment that was not modified performed as before. The reactor vessel pressure was controlled at the same operating point for all of the uprated power conditions. No unexpected performance was observed except in the fine-tuning of the turbine bypass opening that was done as the series of tests progressed. These large transient tests at KKL demonstrated the response of the equipment and the reactor response. The close matches observed with predicted response provide additional confidence that the uprate licensing analyses consistently reflected the behavior of the plant.

Plant Modeling, Data Collection, and Analyses

From the power uprate experience discussed above, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about transient modeling or actual plant response. Since the VYNPS uprate does not involve reactor pressure changes, this experience is considered applicable.

The safety analyses performed for VYNPS used the NRC-approved ODYN transient modeling code. The NRC accepts this code for GE BWRs with a range of power levels and power densities that bound the requested power uprate for VYNPS. The ODYN code has been benchmarked against BWR test data and has incorporated industry experience gained from previous transient modeling codes. ODYN uses plant specific inputs and models all the essential physical phenomena for predicting integrated plant response to the analyzed transients. Thus, the ODYN code will accurately and/or conservatively predict the integrated plant response to these transients at CPPU power levels and no new information about transient modeling is expected to be gained from performing these large transient tests.

CONCLUSION

VYNPS believes that sufficient justification has been provided to demonstrate that an MSIV closure test, turbine trip test, and generator load rejection test is not necessary or prudent. Also, the risk imposed by intentionally initiating large transient testing should not be incurred unnecessarily. As such, Entergy does not plan to perform additional large transient testing following the VYNPS CPPU.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 229 TO FACILITY OPERATING LICENSE NO. DPR-28

ENTERGY NUCLEAR VERMONT YANKEE, LLC

AND ENTERGY NUCLEAR OPERATIONS, INC.

VERMONT YANKEE NUCLEAR POWER STATION

DOCKET NO. 50-271

Proprietary information pursuant to
Title 10 of the *Code of Federal Regulations* Section 2.390
has been redacted from this document.
Redacted information is identified by blank space enclosed within double brackets.

- Core spray and RHR pump seals were evaluated for possible replacement. As discussed in SE Section 2.2.4.2, the seals were requalified for EPU conditions and did not need to be replaced. Leak check testing to be performed at pump-rated conditions.

- Feedwater system pump modifications to include the addition of two sequential levels of low suction pressure trips at various time delays to ensure only one pump trips at a time. Normal modification testing, with breakers in "test" position, to be performed.

The licensee stated that evaluations of the actual test results may identify the need for additional tests or the revision of the tests planned and therefore, the final test plan may be revised. The NRC staff also reviewed the EPU modification aggregate impact analysis, submitted by the licensee in Reference 4, which concluded that there is no adverse impact to the dynamic response of the plant to anticipated initiating events as a result of the proposed plant modifications.

The NRC staff concludes, based on review of each identified modification, the associated post-maintenance test, and the basis for determining the appropriate test, that the EPU test program will adequately demonstrate the performance of SSCs important to safety and included those SSCs: (1) impacted by EPU-related modifications; (2) used to mitigate an AOO described in the plant design basis; and (3) supported a function that relied on integrated operation of multiple systems and components. Additionally, the staff concludes that the proposed test program adequately identified plant modifications necessary to support operation at the EPU power level, and that there were no unacceptable system interactions because of proposed modifications to the plant.

SRP 14.2.1 Section III.C
Use of Evaluation To Justify Elimination of Power-Ascension Tests

Draft SRP 14.2.1, Section III.C, specifies the guidance and acceptance criteria that the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be considered for inclusion in the EPU test program pursuant to the review criteria of SRP 14.2.1, Sections III.A and III.B. The proposed EPU test program shall be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- previous operating experience;

- introduction of new thermal-hydraulic phenomena or identified system interactions;

- facility conformance to limitations associated with analytical analysis methods;

- plant staff familiarization with facility operation and trial use of operating and emergency operating procedures;

- margin reduction in safety analysis results for AOOs;
- guidance contained in vendor topical reports; and
- risk implications.

The NRC staff reviewed the licensee's justification, in Attachment 2 of Reference 20, for not re-performing certain original startup tests. The attachment provides summaries from historical startup testing records and further justifies not performing certain startup tests during EPU power ascension testing. This information supplemented the bases for the proposed testing program provided in Reference 4. The EPU power ascension test plan does not include all of the power ascension testing that would typically be performed during initial startup of a new plant. The following factors were applied by the licensee in determining which tests may be excluded from EPU power ascension testing:

- Previous operating experience has demonstrated acceptable performance of SSCs under a variety of steady state and transient conditions.
- The effects of the VYNPS EPU are in conformance with the criteria of the NRC-approved GE CPPU Licensing Topical Report NEDC-33004P-A (Reference 51). Because the EPU is a constant pressure power uprate, the effects on SSCs due to changes in thermal-hydraulic phenomena are limited.
- Most of the plant modifications associated with the EPU were installed and tested during the spring 2004 refueling outage and subsequent restart. Therefore, modified plant equipment has been in service since that time and plant staff familiarization with changes in plant operation as a result of the modifications has occurred.

The following is a brief justification provided by the licensee with respect to the startup tests that will not be re-performed as part of the EPU power ascension program:

- STP-11, LPRM Calibration. The test is not required to be re-performed since calibration of LPRMs, which is maintained by TSs, is not affected by the EPU.
- STP-13, Process Computer. The test is not required to be re-performed since operation of the process computer is not affected by the EPU. Plant procedures maintain the accuracy of the process computer.
- STP-20, Steam Production. The test is not required to be re-performed since it was only applicable for initial plant startup to demonstrate warranted capabilities.
- STP-21, Response to Control Rod Motion. The test is not required to be re-performed since operation at EPU power increases the upper end of the power operating domain, which does not significantly or directly affect the manner of operating or response of the reactor at lower power levels.

- STP-25, Main Steam Isolation Valves (MSIVs). In accordance with VYNPS TS 4.7.D, each MSIV is tested at least once per quarter by tripping each valve and verifying the closure time. As discussed in Attachment 7 of Reference 1, one of the licensee's justifications for not performing large transient testing is that the initial startup test involving simultaneous closure of all MSIVs would result in an unnecessary and undesirable transient cycle on the primary system which will not likely reveal unforeseen equipment issues related to operation at EPU conditions.

- STP-27, Turbine Trip, and STP-28, Generator Trip. These large transient tests were evaluated by the licensee for exception from EPU power ascension testing in accordance with Attachment 7 of Reference 1. A discussion of the NRC staff's review of the licensee's justification is provided below.

- STP-29, Recirculation Flow Control. Section 3.6 of the VYNPS PUSAR documents that the plant-specific system evaluation of the reactor recirculation system performance at CPPU power determined that adequate core flow can be maintained without requiring any changes to the recirculation system and with only a small increase in pump speed for the same core flow. Because the response to flow changes will be similar to that demonstrated during initial startup testing, this test is not required.

- STP-30, Recirculation System. For a one or two pump trip test at 100% power, Section 3.6 of the PUSAR indicates a CPPU that increases voids in the core during normal EPU operations requires a slight increase in recirculation drive flow to achieve the same core flow. Section 3.6 documents that the plant-specific evaluation of the reactor recirculation system performance at CPPU power determines that adequate core flow can be maintained without requiring any changes to the system or pumps and with only a small increase in their speed for the same core flow. The response to a one or two pump trip will be similar to that of original startup testing, therefore the test is not required.

- STP X-5 (90), Vibration Testing. This test obtains vibration measurements on various reactor pressure vessel internals to demonstrate the mechanical integrity of the system under conditions of FIV and to check the validity of the analytical vibration model. The licensee stated in a previous submittal associated with the steam dryer and other plant systems and components (Reference 16) that the analysis of the vessel internals at the EPU power level was performed to ensure that the design continues to comply with the existing structural requirements. Section 3.4.2 of the PUSAR states that calculations indicate that vibrations of all safety-related reactor internal components under EPU conditions are within GE acceptance criteria.

As mentioned previously in the discussion of startup tests STP-27 and STP-28, the NRC staff also reviewed Attachment 7, "Justification for Exception to Large Transient Testing," contained in Reference 1. The licensee cited industry experience at ten other domestic BWRs (EPUs up to 120% OLTP) in which the EPU demonstrated that plant performance was adequately predicted under EPU conditions. The licensee stated that one such plant, Hatch Units 1 and 2, was granted an EPU by the NRC without the requirement to perform large transient testing and that the VYNPS and Hatch are both BWR/4 designs with Mark I containments. Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from 98% of uprated power in the summer of 1999. As noted in Southern Nuclear Operating Company's licensee event report (LER) 1999-005, no anomalies were seen in the plant's response to this event. In addition, Hatch Unit 1 has experienced a turbine trip and a generator load reject event subsequent to its uprate, as reported in LERs 2000-004 and 2001-002. Again, the behavior of the primary safety systems was as expected indicating that the analytical models being used are capable of modeling plant behavior at EPU conditions.

The licensee also provided information regarding transient testing for the Leibstadt (i.e., KKL) plant which was performed during the period from 1995 to 2000. Uprate testing was performed at 3327 MWt (i.e., 110.5% OLTP) in 1998, 3420 MWt (i.e., 113.5% OLTP) in 1999, and 3515 MWt in 2000. Testing for major transients involved turbine trips at 110.5% OLTP and 113.5% OLTP and a generator load rejection test at 104.2% OLTP. The testing demonstrated the performance of the equipment that was modified in preparation for the higher power levels. These transient tests also provided additional confidence that the uprate analyses consistently reflected the behavior of the plant. Another factor used by the licensee to evaluate the need to conduct large transient testing for the EPU were actual plant transients experienced at the VYNPS. Generator load rejections from 100% current licensed thermal power, as discussed in VYNPS LERs 91-005, 91-009, and 91-014, produced no significant anomalies in the plant's response to these events. Additionally, the licensee indicated that transient experience for a wide range of power levels at operating BWRs has shown a close correlation of the plant transient data to the predicted response.

The NRC staff also reviewed the licensee's technical justification for not performing a loss of turbine generator and offsite power test, which was originally performed at approximately 20% of CLTP. The licensee stated that under emergency operations/distribution (emergency diesel generator) conditions, the AC power supply and distribution components are considered adequate and their evaluation assures an adequate AC power supply to safety-related systems. The TSs and approved plant procedures govern the testing of the safety-related AC distribution system, including loss of offsite power tests.

The power ascension test program is relied upon as a quality check to: (a) confirm that analyses and any modifications and adjustments that are necessary for proposed EPUs have been properly implemented, and (b) benchmark the analyses against the actual integrated performance of the plant thereby assuring conservative results. This is consistent with 10 CFR Part 50, Appendix B, which states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculational methods, or by the performance of a suitable testing program; and requires that design changes be subject to design control measures commensurate with those applied to the original plant design (which includes power ascension testing).

SRP 14.2.1 specifies that the EPU test program should include steady-state and transient performance testing sufficient to demonstrate that SSCs will perform satisfactorily at the requested power level and that EPU-related modifications have been properly implemented.

The SRP provides guidance to the staff in assessing the adequacy of the licensee's evaluation of the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to anticipated operational occurrences.

The NRC staff's review is intended to ensure that the performance of plant equipment important to safety that could be affected by integrated plant operation or transient conditions is adequately demonstrated prior to extended operation at the requested EPU power level. Licensees may propose a test program that does not include all of the power-ascension testing that would normally be included in accordance with the guidance provided in the SRP provided each proposed test exception is adequately justified. If a licensee proposes to omit a specified transient test from the EPU testing program based on favorable operating experience, the applicability of the operating experience to the specific plant must be demonstrated. Plant design details (such as configuration, modifications, and relative changes in setpoints and parameters), equipment specifications, operating power level, test specifications and methods, operating and emergency operating procedures; and adverse operating experience from previous EPUs must be considered and addressed.

Entergy's test program primarily includes steady-state testing with some minor load changes, and no large-scale transient testing is proposed. In a letter dated December 21, 2004 (Reference 60), the NRC staff requested that Entergy provide additional information (including performance of transient testing that will be included in the power ascension test program) that explains in detail how the proposed EPU test program, in conjunction with the original VYNPS test results and applicable industry experience, adequately demonstrates how the plant will respond during postulated transient conditions following implementation of the proposed EPU given the revised operating conditions that will exist and plant changes that are being made. In letters dated July 27, and September 7, 2005 (Reference 60 and 61), the NRC staff requested that the licensee provide additional information regarding the need for condensate and feedwater system transient testing. The results of the staff's review of this issue and the need for a license condition is discussed in SE Section 2.5.4.4.

Based on its review of the information provided by the licensee, as described above, the NRC staff concludes that in justifying test eliminations or deviations, other than the condensate and feedwater system testing discussed in SE Section 2.5.4.4, the licensee adequately addressed factors which included previous industry operating experience at recently uprated BWRs, plant response to actual turbine and generator trip tests at other plants, and experience gained from actual plant transients experienced in 1991 at the VYNPS. From the EPU experience referenced by the licensee, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about transient modeling or actual plant response. As such, the staff concludes that there is reasonable assurance that the VYNPS SSCs will perform satisfactorily in service under EPU conditions. The staff also noted that the licensee followed the NRC staff approved GE topical report guidance which was developed for the VYNPS EPU licensing application.

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Global Nuclear Fuel
A Joint Venture of GE, Toshiba, & Hitachi

0000-0035-6443-SRLR
Revision 0
Class I
December 2005

Supplemental Reload Licensing Report
for
Vermont Yankee Nuclear Power Station
Reload 24 Cycle 25
(with Extended Power Uprate)

8. Operating Flexibility Options [4]

The following information presents the operational domains and flexibility options which are supported by the reload licensing analysis. Inclusion of these results in this report is not meant to imply that these domains and options have been fully licensed and approved for operation.

Extended Operating Domain (EOD):	Yes
EOD type: Maximum Extended Load Line Limit (MELLLA)	
Minimum core flow at rated power:	99.0 %
Increased Core Flow:	Yes
Flow point analyzed throughout cycle:	107.0 %
Feedwater Temperature Reduction:	No
ARTS Program:	Yes
Single Loop Operation:	Yes
Equipment Out of Service:	
Safety/relief valves Out of Service: (credit taken for 3 of 4 relief valves (1 RV OOS))	Yes

9. Core-wide AOO Analysis Results [5]

Methods used: GEMINI, GEXL-PLUS

Operating domain: ICF (HBB) ***Exposure range : BOC to MOC*** ***(Application Condition: 1)***				
			Uncorrected ΔCPR	
Event	**Flux (%rated)**	**Q/A (%rated)**	**GE14C**	**Fig.**
FW Controller Failure	354	121	0.26	2
Load Rejection w/o Bypass	382	119	0.28	3
Turbine Trip w/o Bypass	372	118	0.27	4
Inadvertent HPCI /L8	347	123	0.27	5

[4] Refer to GESTAR for those operating flexibility options that are referenced and supported within GESTAR.
[5] Exposure range designation is defined in Table 7-1. Application condition number is defined in Section 11.

Operating domain: ICF (HBB) Exposure range : MOC to EOC (Application Condition: 1)				
			Uncorrected ΔCPR	
Event	Flux (%rated)	Q/A (%rated)	GE14C	Fig.
FW Controller Failure	379	123	0.26	6
Load Rejection w/o Bypass	400	120	0.27	7
Turbine Trip w/o Bypass	395	120	0.27	8
Inadvertent HPCI /L8	372	125	0.27	9

Operating domain: MELLLA (HBB) Exposure range : BOC to MOC (Application Condition: 1)				
			Uncorrected ΔCPR	
Event	Flux (%rated)	Q/A (%rated)	GE14C	Fig.
FW Controller Failure	314	119	0.25	10
Load Rejection w/o Bypass	328	116	0.26	11
Turbine Trip w/o Bypass	331	116	0.25	12
Inadvertent HPCI /L8	306	121	0.25	13

Operating domain: MELLLA (HBB) Exposure range : MOC to EOC (Application Condition: 1)				
			Uncorrected ΔCPR	
Event	Flux (%rated)	Q/A (%rated)	GE14C	Fig.
FW Controller Failure	328	120	0.25	14
Load Rejection w/o Bypass	337	117	0.26	15
Turbine Trip w/o Bypass	340	117	0.25	16
Inadvertent HPCI /L8	324	122	0.26	17

Operating domain: ICF (UB) Exposure range : MOC to EOC (Application Condition: 1)				
			Uncorrected ΔCPR	
Event	Flux (%rated)	Q/A (%rated)	GE14C	Fig.
FW Controller Failure	250	115	0.25	18
Load Rejection w/o Bypass	301	114	0.27	19
Turbine Trip w/o Bypass	278	114	0.26	20
Inadvertent HPCI /L8	247	118	0.26	21

Operating domain: MELLLA (UB) Exposure range : MOC to EOC (Application Condition: 1)				
			Uncorrected ΔCPR	
Event	Flux (%rated)	Q/A (%rated)	GE14C	Fig.
FW Controller Failure	213	113	0.22	22
Load Rejection w/o Bypass	260	111	0.24	23
Turbine Trip w/o Bypass	238	112	0.24	24
Inadvertent HPCI /L8	207	115	0.23	25

10. Local Rod Withdrawal Error (With Limiting Instrument Failure) AOO Summary

Rod withdrawal error (RWE) limits with ARTS are reported in *Vermont Yankee Nuclear Power Station APRM/RBM/Technical Specifications / Maximum Extended Load Line Limit Analysis (ARTS/MELLLA)*, NEDC-33089P, March 2003. A statistically based RWE limit of 1.40 is established in the *Statistically Based Rod Withdrawal Error Analysis for Vermont Yankee Nuclear Power Station*, GE-NE-0000-0016-3451-R0, July 2003.

A cycle specific analysis was performed for Vermont Yankee Cycle 25 to determine the MCPR corresponding to full withdrawal. (RBM was not credited in this analysis.) For the exposure range from BOC25 to EOC25, it is concluded that the statistically based RWE analysis value of 1.40 bounds the Cycle 25 specific analysis value. Therefore, it is the statistically based value that is reported in Section 11 of the SRLR.

The RBM operability requirements specified in Section 3.4 of ARTS Report NEDC-33089P have been evaluated and shown to be sufficient to ensure that the Safety Limit MCPR and cladding 1% plastic strain criteria will not be exceeded in the event of an unblocked RWE event.

Operating domain: MELLLA (HBB) Exposure range : MOC to EOC (Application Condition: 1)		
	Option A	Option B
	GE14C	GE14C
FW Controller Failure	1.54	1.37
Load Rejection w/o Bypass	1.55	1.38
Turbine Trip w/o Bypass	1.55	1.38
Inadvertent HPCI /L8	1.55	1.38

Operating domain: ICF (UB) Exposure range : MOC to EOC (Application Condition: 1)		
	Option A	Option B
	GE14C	GE14C
FW Controller Failure	1.54	1.37
Load Rejection w/o Bypass	1.57	1.40
Turbine Trip w/o Bypass	1.56	1.39
Inadvertent HPCI /L8	1.55	1.38

Operating domain: MELLLA (UB) Exposure range : MOC to EOC (Application Condition: 1)		
	Option A	Option B
	GE14C	GE14C
FW Controller Failure	1.51	1.34
Load Rejection w/o Bypass	1.53	1.36
Turbine Trip w/o Bypass	1.53	1.36
Inadvertent HPCI /L8	1.52	1.35

12. Overpressurization Analysis Summary

Event	Psl (psig)	Pdome (psig)	Pv (psig)	Plant Response
MSIV Closure (Flux Scram) - ICF (HBB)	1302	1303	1328	Figure 26
MSIV Closure (Flux Scram) - MELLLA (HBB)	1299	1300	1324	Figure 27

ACCESSION #: 9906040026

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Edwin I. Hatch Nuclear Plant - Unit 2 PAGE: 1 OF 5

DOCKET NUMBER: 05000366

TITLE: Generator Ground Fault Causes Turbine Trip and Reactor Scram

EVENT DATE: 05/05/1999 LER #: 1999-005-00 REPORT DATE: 05/27/1999

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 98.3

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION: 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Steven B. Tipps
Nuclear Safety and
Compliance Manager, Hatch
TELEPHONE: (912) 367-7851

COMPONENT FAILURE DESCRIPTION:
CAUSE: B SYSTEM: EL COMPONENT: DUCT MANUFACTURER: N/A
REPORTABLE NPRDS: Yes

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On 05/05/1999 at 0747 EDT, Unit 2 was in the Run mode at a power level of 2716 CMWT (98.3 percent rated thermal power). At that time, the reactor scrammed and the reactor recirculation pumps tripped automatically on turbine control valve fast closure caused by a turbine trip. The turbine tripped when the main generator tripped on a ground fault. Following the reactor scram, water level decreased due to void collapse from the rapid reduction in power. However, the reactor feedwater pumps maintained water level higher than eight inches above instrument zero. Consequently, no safety system actuations on low level were received nor were any required. Pressure reached a maximum value of 1124 psig; nine of eleven safety/relief valves lifted to reduce reactor pressure. Pressure did not reach the nominal actuation setpoints for the remaining two safety/relief valves. The temperature in the vessel bottom head region decreased by more than the Technical Specification-allowed 100 degrees F in one hour before a recirculation pump could be restarted.

This event was caused by a manufacturer error. Some of the turning vanes located in the discharge duct for the "B" isophase bus duct cooling fan broke loose, shorting a generator phase to ground. The manufacturer installed turning vanes that were not the proper thickness for this application thus resulting in some of their connection points failing. Pieces of the broken vanes were retrieved from the isophase bus duct and the remaining turning vanes were removed from the isophase bus duct cooling system.

END OF ABSTRACT

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 05/05/1999 at 0747 EDT, Unit 2 was in the Run mode at a power level of 2716 CMWT (98.3 percent rated thermal power). At that time, the reactor automatically scrammed and the reactor recirculation pumps (EIIS Code AD) automatically tripped on turbine control valve (EIIS Code TA) fast closure caused by a main turbine (EIIS Code TA) trip. The main turbine tripped when the main generator (EIIS Code TB) tripped on a ground fault detected simultaneously by generator neutral ground relays (EIIS Code EL) 2S32-R003A, 2S32-R003B, and 2S32-R003C. A recorded ground fault current of 467 amps energized the neutral ground relays; contacts in the energized relays closed causing the generator output breakers (EIIS Code EL) to open. Opening the generator output breakers energized the main turbine trip relays resulting in fast closure of the turbine control valves. Turbine control valve fast closure is a direct input to the reactor protection system (EIIS Code JC) logic system.

Following the automatic reactor scram, vessel water level decreased due to void collapse from the rapid reduction in power. However, the reactor feedwater pumps (EIIS Code SJ) continued to operate limiting the drop in water level. The minimum water level reached during this event was 8.9 inches above instrument zero (167.34 inches above the top of the active fuel), a decrease of approximately 28 inches from a normal level of 37 inches above instrument zero. Vessel water level did not decrease to the actuation setpoint of three inches above instrument zero. Thus, no safety system, including emergency core cooling system, actuations on low (Level 3) water level were received nor were any required.

Vessel pressure reached a maximum value of 1124 psig three seconds after receipt of the scram. Nine of the eleven safety/relief valves actuated to reduce reactor pressure. Vessel pressure did not reach the nominal actuation setpoint of 1140 psig for safety/relief valves 2B21-F013E and 2B21-F013H; therefore, they did not actuate nor were they required to actuate. (Although safety/relief valve 2B21-F013L has a nominal setpoint of 1140 psig, it actuated during this event. The maximum vessel pressure of 1124 psig was within its Technical Specification-allowed setpoint tolerance of 1115.5 psig to 1184.5 psig. Therefore, the safety/relief valve functioned properly during the event.) Vessel pressure was below its pre-event value of 1033 psig within six seconds of the receipt of the scram. All but the four low-low set safety/relief valves closed within nine seconds of the scram; the low-low set safety/relief valves closed as vessel pressure decreased to their nominal closure setpoints of 890 psig, 881 psig, 866 psig, and 851 psig, respectively.

The temperature in the vessel bottom head region, as measured by the vessel bottom head drain line temperature, decreased by 107 degrees F in less than 22 minutes. Unit 2 Technical Specification Limiting Condition for Operation 3.4.9 limits the reactor coolant system cooldown rate to a maximum of 100 degrees F in one hour. At 0810 EDT, Operations personnel restarted one of the reactor recirculation pumps thereby

increasing the bottom head temperature and reducing the bottom head region temperature drop to less than 100 degrees F.

CAUSE OF EVENT

This event was caused by a manufacturer error. Some of the turning vanes located in the discharge duct for isophase bus duct (EIIS Code EL) cooling fan 2R13-C008B broke loose. One or more of the loose pieces shorted a generator phase to the wall of the isophase bus duct, which is grounded. The manufacturer installed turning vanes that were not the proper thickness (gage) for this application thus resulting in some of the vanes failing at their connection points.

The licensed power level and generator output of Unit 2 were increased during the Fall 1998 refueling outage. Larger fans and their associated duct work were installed in the isophase bus duct cooling system during the outage to remove the increased amount of heat generated in the isophase bus resulting from the increased generator output. The discharge ductwork for cooling fan 2R13-C008B included a 90-degree elbow; the elbow was necessary to connect the "B" fan discharge duct to the common header in the isophase bus duct cooling system. (Due to the location of the "A" cooling fan, no elbow was necessary to connect its discharge duct to the cooling system header.) In order to reduce backpressure resulting from the air hitting the side of the 90-degree elbow opposite the fan discharge, and therefore increase the cooling air flow rate, the ductwork manufacturer installed turning vanes in the elbow. This is a standard practice in designing and constructing ductwork. However, the sheet metal used to construct the vanes and the rails used to connect the vanes to the sides of the elbow was too thin for this application.

Twenty-two gage (0.0336") turning vanes were mounted on 24 gage (0.0276") vane rails and tack welded to the rails at two points on two sides. However, it is difficult to weld sheet metal thinner than 18 gauge. Indeed, a visual check revealed that the vanes broke off near the weld points likely due to metal "burn-out" resulting from welding the thin sheet metal. Additionally, portions of the rail also broke loose from the side of the duct at or near the weld points. Visual examination revealed these points likewise had experienced metal burn-out. Although the gage thickness of the turning vanes was in agreement with the Duct Contraction Standard of the Sheet Metal and Air-Conditioning Contractor National Association, the manufacturer should have used thicker sheet metal since welding was used to secure the vanes and rails. Moreover, the required duct specific pressure rating of 17.1 inches water (air velocity of 4400 fpm) should have indicated a thicker sheet metal had to be used to manufacturer the turning vanes and rails. Therefore, the manufacturer erred in using thinner than 18 gage sheet metal for the turning vanes and rails.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73 (a)(2)(iv) because of the unplanned actuation of Engineered Safety Feature systems. The reactor protection system, an Engineered Safety Feature system, actuated on turbine control valve fast closure when the main turbine tripped following a trip of the main generator from a ground fault. Both reactor recirculation pumps tripped also on turbine control valve fast closure. Nine of eleven

safety/relief valves opened on high vessel pressure; four of the valves continued to operate in the low-low set mode until pressure decreased to their respective closure setpoints.

Fast closure of the turbine control valves is initiated whenever the main generator trips. The turbine control valves close as rapidly as possible to prevent overspeed of the turbine-generator rotor. Valve closing causes a sudden reduction in steam flow that, in turn, results in a reactor vessel pressure increase. If the pressure increases to the pressure relief setpoints, some or all of the safety/relief valves will briefly discharge steam to the suppression pool (EIIS Code BL).

Reactor scram and recirculation pump trip initiation by turbine control valve fast closure prevent the core from exceeding thermal hydraulic safety limits following a main generator or main turbine trip. Closure of the turbine control valves results in the loss of the normal heat sink (main condenser) thereby producing reactor pressure, neutron flux, and heat flux transients that must be limited. A reactor scram is initiated on turbine control valve fast closure in anticipation of these transients. The scram, along with the reactor recirculation pump trip system, ensures that the minimum critical power ratio safety limit is not exceeded.

The recirculation pump trip system, upon sensing a turbine control valve fast closure, trips the reactor recirculation pumps, resulting in a decrease in core flow. The rapid core flow reduction increases void content and reduces reactivity in conjunction with the reactor scram to reduce the severity of the transients caused by the turbine trip.

In this event, the main generator tripped from a ground fault in the isophase bus duct. The main turbine tripped as designed in response to the generator trip. The turbine trip actuated the reactor protection system and scrammed the reactor. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient and indeed never decreased to the Level 3 actuation setpoint. Because the water level decrease was mild, no safety system, including emergency core cooling system, actuations on low water level were received nor were any required.

Typically, the bottom head region of the pressure vessel experiences rapid cooling following a scram coincident with a trip of the reactor recirculation pumps. This cooling is the result of the loss of effective water mixing due to the trip of the recirculation pumps and increased cold water flow from the control rod drive (EIIS Code AA) system following a scram. In this event, the temperature in the vessel bottom head region decreased by 107 degrees F in one hour. However, a bounding analysis indicated cooldown up to 165 degrees F in one hour will not place unacceptable stress on components of the reactor coolant system.

Based upon the preceding analysis, it is concluded this event had no adverse impact on nuclear safety. The analysis is applicable to all power levels.

CORRECTIVE ACTIONS

Pieces of the broken vanes and rails were retrieved from the isophase bus duct.

The remaining turning vanes were removed from the 90-degree elbow in the "B" cooling fan discharge duct. An evaluation by Southern Company Services ensured that the bus cooling flow requirements remain adequate without the turning vanes. The evaluation also ensured no deleterious effects result with respect to the structural integrity of the ductwork and the increased duty on the fan. The "A" cooling fan discharge ductwork does not contain any turning vanes; therefore, no further modification to its ductwork was necessary or performed.

The licensed power level of Unit 1 was increased during the Spring 1999 refueling outage. However, its existing isophase bus duct cooling system was determined previously to be adequate to handle the increased heat load. Therefore, no modifications were performed on this system during the outage and thus no similar problems are expected and no additional work on the system is required.

Personnel assessed the effects of the excessive cooldown rate on the reactor coolant system as required by Unit 2 Technical Specifications Limiting Condition for Operation 3.4.9, Required Action A.2. An evaluation performed by General Electric in May 1994 (NEDC-32319P) was used in assessing the effects of this event. The May 1994 evaluation, intended to eliminate the need to perform an evaluation for each specific event, demonstrated that reactor pressure vessel and recirculation piping heatup and cooldown rates up to 165 degrees F per hour were acceptable provided certain bounding conditions were met. General Electric and Southern Nuclear personnel reviewed the May 1994 evaluation and concluded that the cooldown of 107 degrees F in one hour experienced during this event was bounded by the generic evaluation. Therefore, personnel determined that the Unit 2 reactor coolant system was acceptable for continued operation.

ADDITIONAL INFORMATION

No systems other than those already mentioned in this report were affected by this event.

This LER does not contain any permanent licensing commitments.

Failed Component Information:

Master Parts List Number: 2R13	EIIS System Code: EL
Manufacturer: Ernest D. Menold, Inc	Reportable to EPIX: Yes
Model Number: N/A	Root Cause Code: B
Type: Turning Vanes	EIIS Component Code: DUCT
Manufacturer Code: None	

There have been no previous similar events in the last two years in which the reactor scrammed while critical.

ATTACHMENT TO 9906040026

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SOUTHERN
COMPANY
Energy to Serve Your World**[Servicemark]

May 27, 1999

Docket No. 50-366 HL-5792

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant - Unit 2
Licensee Event Report
Generator Ground Fault Causes Turbine Trip and Reactor Scram

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a generator ground fault which caused a turbine trip followed by a reactor scram.

Respectfully submitted,

H.L. Sumner, Jr.

OCV/eb

Enclosure: LER 50-366/1999-005

cc: Southern Nuclear Operating Company
Mr. P.H. Wells, Nuclear Plant General Manager
SNC Document Management (R-Type A02.001)

U.S. Nuclear Regulatory Commission, Washington, D.C.
Mr. L.N. Olshan, Project Manager - Hatch

U.S. Nuclear Regulatory Commission, Region II
Mr. L.A. Reyes, Regional Administrator
Mr. J.T. Munday, Senior Resident Inspector - Hatch

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SOUTHERN COMPANY
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February 14, 2002

Docket No. 50-366 HL-6184

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant - Unit 2
Licensee Event Report
Sudden Closure of Main Steam Line Isolation Valve Causes
Pressure Increase and Reactor Scram on APRM High Flux

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv)(A), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a sudden closure of a main steamline isolation valve which caused a pressure increase and reactor scram on APRM high flux.

Respectfully submitted,

H. L. Sumner, Jr.

CLT/eb

Enclosure: LER 50-366/2001-003

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager
SNC Document Management (R-Type A02.001)

U.S. Nuclear Regulatory Commission, Washington, D.C.
Mr. L. N. Olshan, Project Manager - Hatch

U.S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator
Mr. J. T. Munday, Senior Resident Inspector - Hatch

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IE22

NRC FORM 366 (7-200 1) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 7/31/2004
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 205550001, or by internet e-mail to bjs1(@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Edwin I. Hatch Nuclear Plant • Unit 2	05000-366	1 OF 4

4. TITLE
Sudden Closure of Main Steam Line Isolation Valve Causes Pressure Increase and Reactor Scram on APRM High Flux.

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S) 05000
12	25	2001	2001	003	0	02	14	2002	FACILITY NAME	DOCKET NUMBER(S) 05000

9. OPERATING MODE: 1

10. POWER LEVEL: 100

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)							
	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20-2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER
	20-2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER	
NAME	TELEPHONE NUMBER (Include Area Code)
Steven B. Tipps, Nuclear Safety and Compliance Manager, Hatch	(912) 367-785 1

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT									
CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
X	SB	SHV	R344	Yes					

14. SUPPLEMENTAL REPORT EXPECTED				15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On 12/25/2001 at 18 19 EST, Unit 2 was in the Run mode. At that time, the reactor scrammed on Average Power Range Monitor high neutron flux caused by a rapid increase in reactor pressure vessel pressure. Pressure increased quickly as a result of the unexpected and sudden closure of main steam line isolation valve 2B21-F028B. The closure of the main steam line isolation valve isolated one of the four main steam lines. Although the flow rates in the remaining three steam lines increased to compensate partially for the isolated line, the sudden isolation of one line was sufficient to cause reactor vessel pressure to increase from a nominal value of 1035 psig to 1041.2 psig within 0.3 seconds. This rapid rate of change in pressure caused reactor power to increase to 120.5 percent rated thermal power and the reactor to scram on high neutron flux level. Following the scram, water level decreased due to void collapse from the rapid reduction in power resulting in closure of Group 2 primary containment isolation valves. Level reached a minimum of 33.5 inches below instrument zero, a level not low enough to initiate other protective actions. Therefore, no systems other than the Group 2 primary containment isolation valves actuated or were required to actuate. The Reactor Feedwater Pumps restored level to its pre-event value of approximately 36 inches above instrument zero within 30 seconds of the scram. Reactor pressure reached its maximum value of 1048.2 psig less than one second after the scram. It decreased thereafter and was maintained below 975 psig by the main turbine bypass valves. No safety/relief valves lifted nor were any required to lift to reduce pressure.

This event was the result of component failure caused by high-cycle fatigue. The stem in valve 2B21-F028B failed completely, causing the valve to close and reactor vessel pressure to increase. Corrective actions include replacing the stem and determining the feasibility and cost of options to reduce or eliminate stem vibration.

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Edwin I. Hatch Nuclear Plant - Unit 2	05000-366	2001	-- 003 --	00	2 OF 4

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 12/25/200 1 at 18 19 EST, Unit 2 was in the Run mode. At that time, the reactor scrammed on Average Power Range Monitor (APRM, EIIS Code IG) high neutron flux after reactor power had increased to approximately 120.5 percent rated thermal power as a result of a rapid increase in reactor pressure vessel pressure. Pressure increased quickly as a result of the unexpected and sudden closure of main steam line isolation valve (EIIS Code SB) 2B2 1-F028B. The closure of the main steam line isolation valve isolated one of the four main steam lines (EIIS Code SB). Although the flow rates in the remaining three steam lines increased to compensate partially for the isolated line, the sudden isolation of one steam line was sufficient to cause reactor vessel pressure to increase from a nominal value of 1035 psig to 1041.2 psig within 0.3 seconds. This rapid rate of change in pressure caused reactor power to increase to 120.5 percent rated thermal power within the same 0.3-second period and the reactor to scram on high neutron flux level per design.

Following the automatic reactor scram, vessel water level decreased due to void collapse from the rapid reduction in power. Water level reached a minimum of 33.5 inches below instrument zero (approximately 125 inches above the top of the active fuel) resulting in closure of the Group 2 primary containment isolation valves (EIIS Code JM). Water level, however, did not decrease to the actuation setpoint for any other protective action system; therefore, no systems other than the Group 2 primary containment isolation valves actuated or were required to actuate.

The Reactor Feedwater Pumps (EIIS Code SJ) rapidly recovered reactor vessel water level, restoring level to its pre-event value of approximately 36 inches above instrument zero within 30 seconds of the scram.

Reactor pressure reached its maximum value of 1048.2 psig 0.6 seconds after the scram. It decreased thereafter and was maintained below 975 psig by the main turbine bypass valves. No safety/relief valves lifted nor were any required to lift to reduce pressure.

CAUSE OF EVENT

This event was the result of component failure. Specifically, the stem in main steam line isolation valve 2B2 1-F028B failed completely from high-cycle fatigue, causing the stem disc (pilot valve) to fall to the closed position. Failure initiation was in the root region of the first thread at the disc-end of the stem. When the stem disc closed, differential pressure forces on the main valve disc (poppet) caused it to close suddenly. The sudden closing of the main steam isolation valve caused reactor vessel pressure to increase from a nominal value of 1035 psig to 1041.2 psig within 0.3 seconds. This rapid rate of change in pressure caused reactor power to increase to 120.5 percent rated thermal power within the same 0.3-second period and the reactor to scram on high neutron flux level per design.

The reason the main steam line isolation valve stem failed due to high-cycle fatigue could not be determined conclusively. The available data support no definitive conclusions regarding the causes of the stem failure. High-cycle fatigue occurs when the number of cycles and level of stress exceed the endurance limit of the failed material. Poor surface conditions and degradation of material condition can reduce the stem material's endurance limit to the point that normal cyclic loading would be sufficient to result in fatigue failure. Conversely, cyclic loading stresses and frequency could change such that the expected material endurance limit would be exceeded. The number of cycles and/or the level of stress experienced by isolation valve 2B2 1-F028B may be different from other isolation valves whose stems have not failed. Also, the stem material's endurance limit may be different: either it changed while the stem was in service (material condition) or it was reduced by a defect (stress riser) in this stem or both. There is insufficient evidence, however, to determine to what extent, if any, these factors contributed to the high-cycle fatigue failure.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73 (a)(2)(iv)(A) because of the unplanned actuation of reportable systems. Specifically, the reactor protection system (EIIS Code JC) actuated on APRM high neutron flux. Group 2 primary containment isolation valves closed as a result of the expected reactor vessel water level decrease following the scram.

Two isolation valves are welded in a horizontal run in each of the four main steam lines. Each of the main steam line isolation valves is a 24-inch, Y-pattern, globe valve. The main valve disc is attached to the lower end of the stem and moves in guides at a 45-degree angle from the inlet pipe. Normal steam flow and higher inlet pressure tend to close the main valve disc. A stem disc attached to the end of the valve stem closes a small pressure-balancing hole in the main disc. When the pressure-balancing hole is open, it acts as a pilot valve to relieve these differential pressure forces on the main disc thereby allowing it to open.

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the local power range monitors (EIIS Code IG) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these local power range monitor signals to provide a continuous indication of average reactor power from a few percent to greater than rated thermal power. The APRM high neutron flux function is capable of generating a reactor protection system trip signal in sufficient time to prevent fuel damage or excessive reactor coolant system pressure.

In this event, the reactor scrammed on Average Power Range Monitor high neutron flux resulting from a rapid increase in reactor pressure vessel pressure. Pressure increased quickly as a result of the unexpected and sudden closure of main steam line isolation valve 2B21-F028B. All systems functioned as expected and per their design given the core thermal power, water level, and pressure transients caused by this event. Fuel cladding integrity was not jeopardized because of the rapid response of the APRMs to the neutron flux increase. This response resulted in a reactor scram before the increased energy from the fuel pellets could be transferred fully to the metal cladding. Additionally, reactor vessel water level was maintained well above the top of the active fuel throughout the event.

Based upon the preceding analysis, it is concluded this event had no adverse impact on nuclear safety. The analysis is applicable to all power levels.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET	LER NUMBER (6) YEAR	SEQUENTIAL YEAR	REVISION NUMBER	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 2	05000-366	2001	-- 003	-- 00	4 OF 4

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

CORRECTIVE ACTIONS

The main steam line isolation valve stem was replaced per Maintenance Work Order 2-01-03746. Local leak rate testing, valve cycling, and valve stroke timing were performed successfully and the valve was returned to an operable status.

Southern Nuclear will perform an investigation to determine the feasibility and cost of options to reduce or eliminate main steam line isolation valve stem assembly vibration.

ADDITIONAL INFORMATION

No systems other than those already mentioned in this report were affected by this event.

This LER does not contain any permanent licensing commitments.

Failed Component Information:

Master Parts List Number: 2B21-F028B
Manufacturer: Rockwell International
Model Number: 16 12 JM MNTY
Type: Valve, Shutoff
Manufacturer Code: R344

EIIS System Code: SB
Reportable to EPIX: Yes
Root Cause Code: X
EIIS Component Code: SHV

Previous similar events in the last two years in which the reactor scrammed automatically while critical were reported in the following Licensee Event Reports:

50-321/2000-002, dated 2/25/2000
50-321/2000-004, dated 8/4/2000
50-321/2001-002, dated 5/21/2001
50-366/2001-002, dated 12/14/2001.

Corrective actions for these previous similar events could not have prevented this event because they involved different components and were the result of different causes.

11

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SOUTHERN COMPANY
Energy to Serve Your World™

August 4, 2000

Docket No. 50-321

HL-5967

U.S. Nuclear Regulatory Commission
ATTN Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant - Unit 1
Licensee Event Report
Component Failure Causes Turbine Trip and Reactor Scram

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a component failure which resulted in a turbine trip and reactor scram.

Respectfully submitted,

Lewis Sumner

H. L. Stunner, Jr.

OCV/eb

Enclosure: LER 50-321/2000-004

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager
SNC Document Management (R-Type A02.001)

U.S. Nuclear Regulatory Commission. Washington D.C.
Mr. L. N. Olshan, Project Manager - Hatch

U.S. Nuclear Regulatory Commission. Region II
Mr. L. A. Reyes, Regional Administrator
Mr. J. T. Munday, Senior Resident Inspector - Hatch

IE22

NRC FORM 366 (06-1998)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)		Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Information and Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If a document used to impose an information collection does not display a currently valid OMB stop number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 1	05000-321	1 OF 6

TITLE (4)
Component Failure Causes Turbine Trip and Reactor Scram

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S)
										05000
07	10	2000	2000	004	00	08	04	2000		DOCKET NUMBER(S) 05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
POWER LEVEL (10)	99.7		20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
			20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
			20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Steven B. Tipps, Nuclear Safety and Compliance Manager, Hatch	(912) 367-7851

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
X	TA	VT	G080	Yes						

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-space typewritten lines) (16)

On 07/10/2000 at 1050 EDT, Unit 1 was in the Run mode at a power level of 2754 CMWT (99.7 percent rated thermal power). At that time, the reactor scrammed and the reactor recirculation pumps tripped automatically on turbiie stop valve fast closure caused by a turbine trip. The turbine tripped when the vibration instrument on the #10 bearing failed causing a false high vibration trip signal to be generated. Following the reactor scram, water level decreased due to void collapse from the rapid reduction in power. However, the reactor feedwater pumps maintained water level higher than seventeen inches above instrument zero. Consequently, no safety system actuations on low level were received nor were any required. Pressure reached a maximum value of 1128 psig; nine of eleven safety/relief valves lifted to reduce reactor pressure. Pressure did not reach the nominal actuation setpoints for the remaining two safety/relief valves. The temperature in the vessel bottom head region decreased by more than the Technical Specification allowed 100°F in one hour before a recirculation pump could be re-started.

This event was caused by component failure. The vibration instrument on the #10 bearing failed, generating a false high vibration signal. The high vibration signal caused the main turbine to trip, producing a reactor scram on turbine stop valve fast closure per design. The failed vibration instrument was replaced. The vibration instruments on the remaining bearings were checked resulting in the replacement of the shaft rider probe on the #6 bearing. No other instrument problems were found.

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Edwin I. Hatch Nuclear Plant - Unit 1	05000-321	2000	- 004	- 00	2 OF 6

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 07/10/2000 at 1050 EDT, Unit 1 was in the Run mode at a power level of 2754 CMWT (99.7 percent rated thermal power). At that time, the reactor automatically scrammed and the reactor recirculation pumps (EIIS Code AD) automatically tripped on turbine stop valve (EIIS Code TA) fast closure caused by a main turbine (EIIS Code TA) trip. The main turbine tripped when the vibration instrument on the #10 bearing, the main generator exciter (EIIS Code TB) outboard bearing, failed. The instrument failure produced a false high bearing vibration signal, causing the main turbine to trip automatically on high bearing vibration. The turbine trip resulted in fast closure of the turbine stop valves. Turbine stop valve fast closure is a direct input to the reactor protection system (EIIS Code JC) logic system.

Following the automatic reactor scram, vessel water level decreased due to void collapse from the rapid reduction in power. However, the reactor feedwater pumps (EIIS Code SJ) continued to operate limiting the drop in water level. The minimum water level reached during this event was eighteen inches above instrument zero (176.44 inches above the top of the active fuel), a decrease of approximately 19 inches from a normal level of 37 inches above instrument zero. Vessel water level did not decrease to the actuation setpoint of three inches above instrument zero. Thus, no safety system, including emergency core cooling system, actuations on low water level were received nor were any required.

Vessel pressure reached a maximum value of 1128 psig after receipt of the scram. Nine of the eleven safety/relief valves actuated to reduce reactor pressure. Vessel pressure did not reach the nominal actuation setpoint of 1140 psig for safety/relief valves IB21-F013E and IB21-F013J; therefore, they did not actuate nor were they required to actuate. (Although safety/relief valve IB21-F013B has a nominal setpoint of 1140 psig, it actuated during this event. The maximum vessel pressure of 1128 psig was within its Technical Specification-allowed setpoint tolerance of 1115.5 psig to 1184.5 psig. Therefore, the safety/relief valve functioned properly during the event.) As vessel pressure was reduced below its pre-event value of 1034 psig, all but the four low-low set safety/relief valves closed. The low-low set safety/relief valves closed as vessel pressure decreased to 883 psig, 874 psig, 859 psig, and 843 psig, respectively.

Non-emergency 4160-volt bus 1B failed to trader automatically from its normal to its alternate supply as expected when the main turbine tripped. Operations personnel manually energized the bus, which provides power to the 1B reactor recirculation pump, from its alternate supply at 1115 EDT.

The reactor coolant temperature in the vessel bottom head region, as measured by the vessel bottom head drain line temperature, decreased by 180°F in one hour. Unit 1 Technical Specification Limiting Condition for Operation 3.4.9 limits the reactor coolant system cooldown rate to a maximum of 100°F in one hour.

Because the temperature difference between the bottom head coolant temperature and the reactor coolant temperature in the steam dome exceeded the maximum allowed by Unit 1 Technical Specifications Surveillance Requirement SR 3.4.9.3, the reactor recirculation pumps could not be restarted. Therefore, the bottom head coolant temperature continued to decrease as expected, albeit at a rate within the 100°F per hour limit.

CAUSE OF EVENT

This event was caused by component failure. The vibration instrument on the #10 bearing, the main generator exciter outboard bearing, failed when a solder connection inside the shaft rider probe came apart. This created a loose wire that made intermittent contact with a coil within the probe. The loose wire contacted the coil such that a false high vibration signal was generated. The high vibration signal caused the main turbine to trip automatically, producing a reactor scram on turbine stop valve fast closure per design.

Non-emergency 4160-volt bus 1B failed to transfer automatically because its normal supply breaker was slow in opening. The automatic transfer logic requires the normal supply breaker to open within ten cycles (166.7 milliseconds). If the normal supply breaker does not open within the required time, the transfer logic prevents the alternate supply breaker from closing. The first test of the normal supply breaker performed after it had opened during the event revealed that the breaker opened in 124 milliseconds, nearly three times the procedural acceptance criterion of 45 milliseconds. Subsequent tests of the breaker indicated it would open faster the more it was exercised. For example, the breaker opened in 114 milliseconds during the third test and 91.6 milliseconds during the fourth test, a 26 percent improvement from the time recorded in the first test. Finally, testing revealed that actuation of the logic necessary to indicate that the normal supply breaker was open added 33 to 50 milliseconds to the transfer logic signal. Considering this additional time and the likelihood that the opening time of the normal supply breaker was greater than 124 milliseconds, investigating personnel concluded that the breaker opened too slowly, preventing transfer to the alternate power supply.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73 (a)(2)(iv) because of the unplanned actuation of Engineered Safety Feature systems. The reactor protection system, an Engineered Safety Feature system, actuated on turbine stop valve fast closure when the main turbine tripped on a false high bearing vibration signal. Both reactor recirculation pumps tripped also on turbine stop valve fast closure. Nine of eleven safety/relief valves opened on high vessel pressure; four of the valves continued to operate in the low-low set mode until pressure decreased to their respective closure setpoints.

Fast closure of the turbme stop valves is initiated whenever the main turbine tips. The turbme stop valves close as rapidly as possible to prevent overspeed of the turbine-generator rotor. Valve closing causes a sudden reduction in steam flow that, in turn results in a reactor vessel pressure increase. If the pressure increases to the pressure

FACILITY NAME (1)	DOCKET	LER NUMBER (6) YEAR	SEQUENTIAL YEAR	REVISION NUMBER	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 1	05000-321	2000	004	00	4 OF 6

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

relief setpoints, some or all of the safety/relief valves will briefly discharge steam to the suppression pool (EIIS Code BL).

Reactor scram and recirculation pump trip initiation by turbine stop valve fast closure prevent the core from exceeding thermal hydraulic safety limits following a main turbiie trip. Closure of the turbiie stop valves results in the loss of the normal heat sink (main condenser) thereby producing reactor pressure, neutron flux, and heat flux transients that must be limited. A reactor scram is initiated on turbine stop valve fast closure in anticipation of these transients. The scram, along with the reactor recirculation pump trip system, ensures that the minimum critical power ratio safety limit is not exceeded.

The recirculation pump trip system, upon sensing a turbiie stop valve fast closure, trips the reactor recirculation pumps, resulting in a decrease in core flow. The rapid core flow reduction increases void content and reduces reactivity in conjunction with the reactor scram to reduce the severity of the transients caused by the turbine trip.

In this event, the main turbine tripped on a false high bearing vibration trip signal. The turbine trip actuated the reactor protection system and scrammed the reactor. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbiie trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient and indeed never decreased to the Level 3 actuation setpoint. Because the water level decrease was mild, no safety system actuations on low water level were received nor were any required.

Typically, the bottom head region of the pressure vessel experiences rapid cooling following a scram coincident with a trip of the reactor recirculation pumps. This cooling is the result of the loss of effective water mixing due to the trip of the recirculation pumps and increased cold water flow from the control rod drive (EIIS Code AA) system following a scram. In this event, the temperature in the vessel bottom head region decreased by 180°F in one hour. However, a bounding analysis indicated cooldown up to 397.7°F in one hour will not place unacceptable stress on components of the reactor coolant system.

Based upon the preceding analysis, this event had no adverse impact on nuclear safety. The analysis is applicable to all power levels.

CORRECTIVE ACTIONS

The vibration instrument for the #10 bearing was replaced on 7/12/2000 per Maintenance Work Order 1-00-02145. Additionally, the remaining vibration instruments were checked on 7/12/2000 per Maintenance Work Order 1-00-02159. As a result of this inspection, the shaft rider probe of the vibration instrument for the #6 bearing was replaced. No problems were found with any of the other bearing vibration instruments.

The high bearing vibration trip from the #9 and #10 bearings, with the concurrence of the turbine vendor, has been temporarily disabled. The final disposition of the main turbine high bearing vibration trips will be determined through the corrective action program.

Personnel assessed the effects of the excessive cooldown rate on the reactor coolant system. An evaluation performed by General Electric in May 1994 (NEDC-323 19P) was used in assessing the effects of this event. The May 1994 evaluation, intended to eliminate the need to perform an evaluation for each specific event, demonstrated that reactor pressure vessel cooldown rates up to 397.7°F per hour were acceptable provided certain bounding conditions were met. General Electric and Southern Nuclear personnel reviewed the May 1994 evaluation and concluded that the cooldown of 180% in one hour experienced during this event was bounded by the generic evaluation. Therefore, personnel determined that the Unit 1 reactor coolant system was acceptable for operation.

The normal supply breaker for non-emergency 4160-volt bus 1B was removed and replaced with a refurbished breaker on 7/12/2000 per Maintenance Work Order 1-99-04564. A fast transfer functional test of the newly installed normal supply breaker was completed successfully.

ADDITIONAL INFORMATION

No systems other than those already mentioned in this report were affected by this event.

This LER does not contain any permanent licensing commitments.

Failed Component Information:

Master Parts List Number: IN3 1-N892	EIIS System Code: TA
Manufacturer: General Electric	Reportable to EPIC: Yes
Model Number: 3S7700VB100A1	Root Cause Code: X
Type: Vibration Transmitter	EIIS Component Code: VT
Manufacturer Code: GO80	

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Edwin I. Hatch Nuclear Plant - Unit 1	05000-321	2000	-- 004 --	00	6 OF 6

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

previous similar events in the last two years in which the reactor scrammed automatically while critical were reported in the following Licensee Event Reports:

50-321/1999-003 dated 6/1/1999
50-321/2000-002 dated 2/25/2000
50-366/1999-005 dated 5/27/1999
50-366/1999-007 dated 7/27/1999

Corrective actions for these previous similar events could not have prevented this event because their causes were different. Specifically, none of the other previous similar events was the result of an instrument failure. Indeed, only one of the previous four events was caused by a main turbine trip. In that event, reported in Licensee Event Report 50-366/1999-005, the main turbiie tripped when the main generator tripped on an actual ground fault. Therefore, any corrective actions taken for the previous events would not have addressed turbiie bearing vibration instruments.

Lewis Sumner
Vice President
Hatch Project Support

Southern Nuclear
Operating Company, Inc.
40 Inverness Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205992.7279
Fax 205.992.0341

SOUTHERN COMPANY
Energy to Serve Your World℠

May 21, 2001

Docket No. 50-321

HL-6088

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Edwin I. Hatch Nuclear Plant - Unit 1
Licensee Event Report
Component Failure Causes Turbine Trip and Reactor Scram

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(iv)(A), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a component failure which caused a turbine trip and reactor scram.

Respectfully submitted,

H. L. Sumner, Jr.

DMC/eb

Enclosure: LER 50-321/2001-002

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager
SNC Document Management (R-Type A02.001)

U.S. Nuclear Regulatory Commission, Washington, D.C.
Mr. L. N. Olshan, Project Manager - Hatch

U.S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator
Mr. J. T. Munday, Senior Resident Inspector - Hatch

Institute of Nuclear Power Operations
LEREvents@inpo.org
AitkenSY@Inpo.org

IE22

NRC FORM 366 (1-2001) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 1	05000-321	1 OF 4

TITLE (4)
Component Failure Causes Turbine Trip and Reactor Scram

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S) 05000
03	28	2001	2001	002	00	05	21	2001		DOCKET NUMBER(S) 05000

OPERATING MODE (9): 1
POWER LEVEL (10): 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20-2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER
	20-2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Steven B. Tipps, Nuclear Safety and Compliance Manager, Hatch	(912) 367-7851

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
X	EA	XFMR	G080	Yes					

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-space typewritten lines) (16)

On 03/28/2001 at 1853 EST, Unit 1 was in the Run mode at a power level of 2763 CMWT (100 percent rated thermal power). At that time, the reactor scrammed on turbine control valve fast closure caused by a turbine trip. The turbine tripped when actuation of phase 2 and 3 differential relays for unit auxiliary transformer 1B resulted in actuation of a lockout relay, generating a direct turbine trip signal. Following the scram, water level decreased due to void collapse from the rapid reduction in power resulting in closure of Group 2 and the outboard Group 5 primary containment isolation valves and automatic initiation of the Reactor Core Isolation Cooling and High Pressure Coolant Injection systems. The low level initiation signal cleared before either system could inject water to the vessel. The outboard secondary containment dampers automatically isolated, and all trains of the Unit 1 and Unit 2 Standby Gas Treatment systems automatically started on low water level. Level reached a minimum of 37 inches below instrument zero. The Reactor Feedwater Pumps restored level to its pre-event value of approximately 35 inches above instrument zero within 30 seconds of the scram. Pressure reached a maximum value of 1127 psig; five of eleven safety/relief valves lifted to reduce pressure. Pressure did not reach the nominal actuation setpoints for the remaining safety/relief valves.

This event was caused by an internal fault in unit auxiliary transformer 1B. The fault occurred on the high side winding of transformer phase 3. The transformer was removed from service; its loads will continue to be supplied from their alternate supply until a new transformer can be procured and installed.

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes appear in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 03/28/2001 at 1853 EST, Unit 1 was in the Run mode at a power level of 2763 CMWT (100 percent rated thermal power). At that time, the reactor automatically scrammed on turbine control valve (EIIS Code TA) fast closure caused by a main turbine (EIIS Code TA) trip. The main turbine tripped when actuation of phase 2 and phase 3 differential relays monitoring unit auxiliary transformer 1B (EIIS Code EA) resulted in actuation of lockout relay 87T1BX. Actuation of this lockout relay generated a direct turbine trip signal and the main turbine tripped per design. The turbine trip resulted in fast closure of the turbine control valves. Turbine control valve fast closure is a direct input to the reactor protection system (EIIS Code JC).

Following the automatic reactor scram, vessel water level decreased due to void collapse from the rapid reduction in power. Water level reached a minimum of approximately 37 inches below instrument zero (approximately 121 inches above the top of the active fuel) resulting in closure of the Group 2 and outboard Group 5 primary containment isolation valves (EIIS Code JM) and automatic initiation of the Reactor Core Isolation Cooling (RCIC, EIIS Code BN) and High Pressure Coolant Injection (HPCI, EIIS Code BJ) systems. The outboard secondary containment isolation dampers automatically closed and all four trains of the Unit 1 and Unit 2 Standby Gas Treatment (EIIS Code BH) systems (SGTS) automatically started.

The Reactor Feedwater Pumps (EIIS Code SJ) rapidly recovered reactor vessel water level, restoring level to its pre-event valve of approximately 35 inches above instrument zero within 30 seconds of the scram. As a result, the HPCI and RCIC system low water level initiation signals cleared before either system could inject makeup water to the reactor vessel. Also, the inboard Group 5 primary containment isolation valve and the inboard secondary containment isolation dampers did not close because water level increased before all of the logic necessary to isolate the inboard valve and dampers sensed, and could actuate on, a low, water level condition.

Vessel pressure reached a maximum value of 1127 psig after receipt of the scram. Five of the eleven safety/relief valves actuated to reduce reactor pressure. Vessel pressure did not reach the nominal actuation setpoints of the remaining safety/relief valves; therefore, they did not actuate nor were they required to actuate. (Although safety/relief valve 1B21-F013B has a nominal setpoint of 1140 psig, it actuated during this event. The maximum vessel pressure of 1127 psig, however, was within its Technical Specification-allowed setpoint tolerance of 1115.5 psig to 1184.5 psig. Therefore, the safety/relief valve functioned properly during the event.) As vessel pressure was reduced, the low-low set safety/relief valves closed at 887 psig, 877 psig, 862 psig, and 847 psig, respectively. The main turbine bypass valves functioned to control vessel pressure thereafter, maintaining pressure below 975 psig.

CAUSE OF EVENT

This event was caused by an internal fault in unit auxiliary transformer 1B. An inspection revealed a turn-to-turn failure caused extensive damage to the high side winding of transformer phase 3. Although an Event Review Team investigated this event, the root causes of the transformer internal fault were not determined.

Some evidence gathered by the Event Review Team, that is, transformer winding temperatures from Main Control Room recorder 1N41-R900, six-month load voltage readings, and transformer operating history, appeared to indicate the possibility of a load-induced or cooling-related problem as the direct cause of the transformer fault. However, other evidence, such as the periodic recording of local transformer winding and oil temperature gauge readings, which indicated temperatures significantly lower than the recorder readings, and a successful check of transformer temperature switch operation, was inconsistent with this conclusion.

An internal transformer fault might have developed if contamination had been introduced in 1999 when part of phase 3 was re-wound as a result of a problem discovered during routine- testing of the transformer. However, the damage from the fault destroyed any evidence that might have existed. Therefore, it is impossible to confirm the presence, or lack, of contamination and to prove, or disprove, contamination as the direct cause of the internal fault in unit auxiliary transformer 1B. It should be noted that internal contamination almost certainly was not the cause of failures of the high side winding of transformer phase 3 in 1984 and 1999 due to the many years of in-service time between those failures, making it less likely to be the cause for this most recent similar failure.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73 (a)(2)(iv)(A) because of the unplanned actuation of reportable systems. Specifically, the reactor protection system actuated on turbine control valve fast closure when the main turbine tripped following the detection of a fault in unit auxiliary transformer 1B. Group 2 and outboard Group 5 primary containment isolation valves closed and the RCIC and HPCI systems initiated. Five of eleven safety/relief valves opened on high vessel pressure; four of the valves continued to operate in the low-low set mode until pressure decreased to their respective closure setpoints.

Fast closure of the turbine control valves is initiated whenever the main turbine trips. The turbine control valves close as rapidly as possible to prevent overspeed of the turbine-generator rotor. Valve closing causes a sudden reduction in steam flow that, in turn, results in a reactor vessel pressure increase. If the pressure increases to the pressure relief setpoints, some or all of the safety/relief valves will briefly discharge steam to the suppression pool (EIIS Code BL).

Reactor scram initiation by turbine control valve fast closure prevents the core from exceeding thermal hydraulic safety limits following a main turbine trip. Closure of the turbine control valves results in the loss of the normal heat sink (main condenser, EIIS Code SQ) thereby producing reactor pressure, neutron flux, and heat flux transients that must be limited. A reactor scram is initiated on turbine control valve fast closure in anticipation of these transients. The scram ensures that the minimum critical power ratio safety limit is not exceeded.

In this event, the main turbine tripped when the unit auxiliary transformer lockout relay actuated on signals from the phase 2 and phase 3 differential current relays. The turbine trip actuated the reactor protection system and scrammed the reactor. All systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Vessel water level was maintained well above the top of the active fuel throughout the transient.

Based upon the preceding analysis, it is concluded this event had no adverse impact on nuclear safety. The analysis is applicable to all power levels.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET	LER NUMBER (6) YEAR	SEQUENTIAL YEAR	REVISION NUMBER	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 1	05000-321	2001	– 002 –	00	4 OF 4

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

CORRECTIVE ACTIONS

The unit auxiliary transformer was removed from service and taken to an off-site facility for further inspection. This inspection revealed extensive damage to the high side windings of phase 3 caused by a turn-to-turn fault. The transformer loads will continue to be supplied from their alternate power supply, startup transformer 1C (EIIS Code EA), until a new transformer can be procured and installed.

ADDITIONAL INFORMATION

No systems other than those already mentioned in this report were affected by this event.

This LER does not contain any permanent licensing commitments.

Failed Component Information:

Master Parts List Number: 1S11-S003
Manufacturer: General Electric
Model Number: NP 167B5 180
Type: Transformer
Manufacturer Code: GO80

EIIS System Code: EA
Reportable to EPIX: Yes
Root Cause Code: X
EIIS Component Code: XFMR

Previous similar events in the last two years in which the reactor scrammed automatically while critical were reported in the following Licensee Event Reports:

50-321/1999-003, dated 6/1/1999
50-321/2000-002, dated 2/25/2000
50-321/2000-004, dated 8/4/2000
50-366/1999-005, dated 5/27/1999
50-366/1999-007, dated 7/27/1999

Corrective actions for these previous similar events could not have prevented this event because they involved different components and were the result of different direct causes.

Similar failures of unit auxiliary transformer 1B occurred in 1984 and 1999. Specifically, the high side windings of phase 3 of the unit auxiliary transformer failed in August 1984 after approximately ten years of service; this event resulted in an unplanned automatic reactor scram while critical (Licensee Event Report 50-321/1984-015, dated 8/30/1984). The high side windings of this phase also failed a routine doble test in March 1999 after almost fifteen years of service; this problem was discovered before the windings had deteriorated to the point of causing an internal transformer fault. The transformer was completely rebuilt as a result of the former event. Part of the high side windings of phase 3 was rebuilt as a result of the latter event. In neither event were the root causes of the failure determined; therefore, the corrective action of repairing the transformer was not intended to address the causes of the failure and to prevent subsequent failures.

13

Progress Energy

January 5, 2004

SERIAL: BSEP 03-0158 10 CFR 50.73

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Subject: Brunswick Steam Electric Plant, Unit No. 2
Docket No. 50-324/License No. DPR-62
Licensee Event Report 2-03-004

Gentlemen:

In accordance with the Code of Federal Regulations, Title 10, Part 50.73, Progress Energy Carolinas, Inc. submits the enclosed Licensee Event Report. This report fulfills the requirement for a written report within sixty (60) days of a reportable occurrence.

Please refer any questions regarding this submittal to Mr. Edward T. O'Neil, Manager – Support Services, at (910) 457-3512.

Sincerely,

David H. Hinds
Plant General Manager
Brunswick Steam Electric Plant

CRE/cre

Enclosure: Licensee Event Report

IE22

Progress Energy Carolinas, Inc.
Brunswick Nuclear Plant
P.O. Box 10429
Southport, NC 28461

cc (with enclosure):

U. S. Nuclear Regulatory Commission, Region II
ATTN: Mr. Luis A. Reyes, Regional Administrator
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
Atlanta, GA 30303-8931

U. S. Nuclear Regulatory Commission
ATTN: Mr. Eugene M. DiPaolo, NRC Senior Resident Inspector
8470 River Road
Southport, NC 28461-8869

U. S. Nuclear Regulatory Commission
ATTN: Ms. Brenda L. Mozafari (Mail Stop OWFN 8G9) (Electronic Copy Only)
11555 Rockville Pike
Rockville, MD 20852-2738

U. S. Nuclear Regulatory Commission
ATTN: Ms. Margaret Chernoff (Mail Stop OWFN 8G9A) (Electronic Copy Only)
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Rockville, MD 20852-2738

Ms. Jo A. Sanford
Chair - North Carolina Utilities Commission
P.O. Box 29510
Raleigh, NC 27626-051

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 7-31-2004
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory information collection request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Brunswick Steam Electric Plant (BSEP), Unit 2	05000324	1 OF 6

4. TITLE
Loss of Generator Excitation Results in Reactor Protection System and Other Specified System Actuations

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME BSEP, Unit 1	DOCKET NUMBER 05000325
11	04	2003	2003	-- 004 --	00	01	05	2004	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE	1
10. POWER LEVEL	96

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more)

	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
	20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
Charles R. Elberfeld, Lead Engineering Technical Support Specialist	(910) 457-2136

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	TL	EXC	General Electric	Y					

14. SUPPLEMENTAL REPORT EXPECTED				15. EXPECTED SUBMISSION DATE	MO	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On November 4, 2003, at approximately 1732 hours, Unit 2 received a generator/turbine trip due to loss of generator excitation, which resulted in a Reactor Protection System (RPS) actuation. All control rods fully inserted into the core. Plant response to the transient also resulted in High Pressure Coolant Injection and Reactor Core Isolation Cooling System actuations on low reactor pressure vessel (RPV) coolant level with injection into the RPV. Additionally, Primary Containment Isolation System (PCIS) actuation signals for Valve Groups 1, 2, 3, 6, and 8 were received and the valves closed as required. All four Emergency Diesel Generators automatically started but did not load because electrical power was not lost to the emergency buses.

The initiator of the plant transient event and system actuations was the failure of the generator exciter inner collector ring and brush holders, which resulted in loss of excitation to the generator. The root cause of the failure is a fabrication deficiency due to poor workmanship at the time of original installation of the collector ring onto the exciter shaft. Weaknesses in brush maintenance, preventive maintenance, monitoring, and trending were also identified as the root cause of the event.

The damaged components were replaced. Enhanced exciter brush monitoring has been implemented on both Units 1 and 2. This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A). The safety significance of this occurrence is considered minimal.

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

INTRODUCTION

On November 4, 2003, at approximately 1732 hours, Unit 2 received a generator/turbine trip due to loss of generator excitation [TL], which resulted in a Reactor Protection System (RPS) [JC] actuation. All control rods fully inserted into the core. Plant response to the transient also resulted in High Pressure Coolant Injection (HPCI) [BJ] and Reactor Core Isolation Cooling (RCIC) [BN] System actuations on low reactor pressure vessel (RPV) coolant level, with injection into the RPV. Additionally, Primary Containment Isolation System (PCIS) [JM] actuation signals for Valve Groups 1, 2, 3, 6, and 8 were received and the valves closed as required. As a result of the associated electrical transient, a PCIS Valve Group 6 isolation was also received on Unit 1. All four Emergency Diesel Generators (EDGs) [EK] automatically started but did not load because electrical power was not lost to the emergency buses. At the time of the event, Unit 2 was in Mode 1, (i.e., Run) at approximately 96 percent of rated thermal power (RTP) and Unit 1 was in Mode 1 at 93 percent of RTP, with all Emergency Core Cooling Systems operable for both units. At approximately 1857 hours, with Unit 2 in Mode 3 (i.e., Hot Shutdown), another RPS actuation was received due to low RPV coolant level while cycling Safety Relief Valves (SRVs) [RV]. At 2120 hours, notification was made to the NRC (i.e., Event Number 40297) in accordance with 10 CFR 50.72(b)(2)(iv)(A), (b)(2)(iv)(B), and (b)(3)(iv)(A). This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A) as manual and automatic actuation of specified systems.

EVENT DESCRIPTION

On November 4, 2003, at approximately 1732 hours, the Unit 2 generator exciter [EXC] inboard collector ring (i.e., Alterrex Serial # CH8371544, General Electric Company, Reference TAB 32'S GEK 18539C Figure 7, Mechanical Outline Drawing GEK 34D105050) and brush holders failed resulting in a loss of generator excitation. The loss of generator excitation resulted in a decrease in generator voltage and AC bus voltages on Unit 2 for about three to four seconds, with a dip to approximately 40 percent of nominal voltage values. After the generator tripped, the Unit 2 bus loads were automatically transferred from the Unit Auxiliary Transformer to the Site Auxiliary Transformer (SAT). Additionally, all four EDGs automatically started, as a result of the generator trip, but did not load because electrical power was not lost to the emergency buses. Upon transfer to the SAT, the bus voltages returned to nominal values. Details of this event will be discussed in two sections: (1) Unit 2 Scram and Associated Transients, and (2) Plant Responses to the Voltage Transient.

Unit 2 Scram and Associated Transients

On November 4, 2003, at approximately 1732 hours, and approximately three seconds into the voltage transient, the Unit 2 generator/turbine tripped, resulting in an RPS actuation. The voltage decrease also resulted in PCIS Valve Group 1 (i.e., Main Steam Isolation valves (MSIVs), Main Steam Line Drain valves, and Reactor Recirculation Sample valves), Group 3 (i.e., Reactor Water Cleanup isolation valves), and Group 6 (i.e., Containment Atmosphere Control/Dilution, Containment Atmosphere Monitoring, and Post

EVENT DESCRIPTION (continued)

Unit 2 Scram and Associated Transients (continued)

Accident Sampling System isolation valves) isolations. Event Notification 40297 stated that a Group 10 (i.e., Non-Interruptible Air to Drywell Isolation Valves) isolation occurred; however, review of the event and plant documentation could not validate the isolation. Four of 11 SRVs opened for a short duration on mechanical setpoints in response to the pressure transient. Maximum RPV steam dome pressure measured during the event was 1108 psig.

RPV coolant level decreased to below the Low Level 1 setpoint, which resulted in a Group 2 (i.e., Drywell Equipment and Floor Drain, Traversing In-core Probe, Residual Heat Removal (RHR) Discharge to Radwaste, and RHR Process Sample isolation valves) isolation and a Group 8 (i.e., RHR Shutdown Cooling Suction and RHR Inboard Injection isolation valves) isolation signal; however, the Group 8 valves were already closed as required by plant conditions prior to the event. RPV coolant level continued to decrease to the Low Level 2 setpoint, at which time the HPCI and RCIC Systems actuated and injected into the RPV to restore level.

After RPV coolant level was restored the HPCI System was secured. RPV coolant level and pressure were controlled using the Control Rod Drive [AA] System flow, the RCIC System, and by manually cycling SRVs. The RHR loops were placed in the suppression pool cooling mode of operation as needed to remove decay heat. Activities were in progress to open the MSIVs to use the main condenser for the reactor cooldown. At approximately 1857 hours, a second RPS actuation was received when RPV coolant level decreased below the Low Level 1 setpoint due to level shrink after an SRV was closed during manual cycling. RPS logic was reset at approximately 1922 hours. At approximately 1934 hours, the MSIVs were opened to re-establish the main condenser as a heat sink. At approximately 2300 hours, the 2B Reactor Feed Pump was started to provide makeup to the RPV and the RCIC System was secured.

On November 5, 2003, at approximately 0452 hours, RHR loop A was placed in the shutdown cooling mode of operation. At approximately 0554 hours, Unit 2 entered Mode 4 (i.e., Cold Shutdown).

Plant Responses to Voltage Transient

On November 4, 2003, at approximately 1732 hours, the loss of Unit 2 generator excitation resulted in a voltage transient on Unit 2 AC buses. The transient was characterized as a voltage decrease for about three or four seconds, with a dip to approximately 40 percent of nominal voltage values, at which time the voltages returned to normal values. The voltage transient caused the main stack radiation monitor, which is common to both Units 1 and 2, to initiate a logic signal resulting in isolation of the Reactor Building Ventilation [VA] Systems, automatic starting of the Standby Gas Treatment (SGT) Systems [BH], and PCIS Group 6 isolations for both units. The affected equipment responded successfully except for the Unit 2 SGT System Train A. Operations personnel reset a high temperature trip signal that was locked in during the voltage transient and were able to successfully start Train A manually.

NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)* (17)

EVENT DESCRIPTION (continued)

Plant Responses to Voltage Transient (continued)

On November 4, 2003, at approximately 1812 hours, the Unit 1 Reactor Building Ventilation System was restarted and at approximately 1825 hours, it was restarted for Unit 2. At approximately 1824 hours, the Unit 1 SGT System was secured and at approximately 2055 hours, the Unit 2 SGT System was placed in standby. The PCIS Group 6 isolations were reset for both units as conditions allowed. By 2034 hours, all four EDGs were placed in standby.

The voltage transient also affected other equipment on both units which required operator action to restore the equipment. The occurrences were evaluated considering the plant design and it was determined that these effects were to be expected based on the nature of the voltage transient and automatic load stripping of the emergency buses. The adequacy of the plant under-voltage protection logic was evaluated in light of the voltage transient associated with this event and it was determined that the present design is adequate.

EVENT CAUSE

Loss of Generator Excitation

The initiator of the plant transient event and system actuations was the failure of the generator exciter inner collector ring and brush holders, which resulted in loss of excitation to the generator. The root cause of the failure is a fabrication deficiency due to poor workmanship at the time of original installation of the collector ring onto the exciter shaft in the early 1970s. The collector ring is designed to have a tight interference fit on the exciter shaft to minimize vibration. The poor workmanship was the fit-up of the collector ring assembly utilizing a peening methodology on the anti-rotation key in lieu of the proper shrink fit of the collector ring on the exciter rotor shaft. Post-failure inspection and laboratory evaluation support this conclusion.

Weaknesses in brush maintenance, preventive maintenance, monitoring, and trending were also identified as the root cause of the event. Comparison of site activities with original equipment manufacturer and industry recommendations indicate that the event may have been avoided if brush and brush rigging vibration monitoring and trending, as well as collector ring strobe light inspection activities, had been implemented per recommendations. On October 21, 2003, during the weekly exciter brush inspection, the three inboard brush currents were noted to be unequal, indicating a degraded condition with the collector ring/brushes. An action plan was developed and being implemented to address the degraded condition, but the activities were not effective in preventing the equipment failure and subsequent event.

Additional contributing causal factors include insufficient detail/incomplete training for maintenance and engineering personnel, as well as inadequate attention to emerging problems and ineffective use of operating experience. General Electric Company notified equipment users of an improved brush holder and rigging design in the early 1990 timeframe. Operating experience from other utilities indicated success with mitigation of brush vibration issues using the improved design. The improved design was not implemented at BSEP.

FACILITY NAME (1)	DOCKET (2)	LER NUMBER (6)			PAGE (3)
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Brunswick Steam Electric Plant (BSEP), Unit 2	05000324	2003	-- 004 --	00	5 OF 6

NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)* (17)

EVENT CAUSE (continued)

Low Level 1 RPS Actuation due to RPV Coolant Level Shrink

The cause of the Low Level 1 RPS actuation is attributed to the level shrink caused by manual SRV cycling until the MSIVs could be re-opened. Although this method is allowed by plant procedures, pressure control using manual SRV cycling is not as stable as using the HPCI System, in the pressure control mode of operation, and the RCIC System.

Unit 2 SGT System Train A Failure to Automatically Start on Demand

Each SGT System train is designed to be able to automatically start after a complete loss of electrical power, and incorporates a specific relay logic scheme to allow that capability. On November 4, 2003, the electrical transient resulted in a short-term voltage drop to approximately 40 percent of the nominal voltage value. The voltage value during the transient decreased to a value where some relays in the start logic may or may not have dropped out. For the Unit 2 SGT System Train A only, the relays responded such that the logic had to be reset before the train could start.

CORRECTIVE ACTIONS

- The damaged components (i.e., the collector ring, the anti-rotation key, the brushes, and brush rigging) were replaced. The collector ring was properly installed on the rotor shaft.
- Preventive maintenance, exciter brush vibration monitoring, and trending program improvements are being developed and will be implemented by February 20, 2004. Program improvements for other brush applications on site are also being considered.
- Enhanced exciter brush monitoring has been implemented on both Units 1 and 2. Unit 1 exciter collector rings are scheduled to be replaced during the next refuel outage, which is scheduled to begin in February 2004.
- Design improvements to the exciter brush holders and inspection windows are being reviewed and developed.
- Training is being developed for appropriate engineering, operations, and maintenance personnel on brush maintenance topics.
- As part of the approved licensed operator training program, this event and the lessons learned associated with RPV coolant level control will be reviewed with the operating crews.
- A modification has been installed in the logic for both SGT System trains for both units to enhance logic response under degraded voltage conditions such as those experienced during this event.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant (BSEP), Unit 2	05000324	2003	-- 004 --	00	6 OF 6

NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)* (17)

SAFETY ASSESSMENT

The safety significance of this occurrence is considered minimal. Plant systems responded as designed to the transient and so the consequences of the transient on the fuel and vessel overpressure were minimal. The analyses in Chapter 15 of the Updated Final Safety Analysis Report fully bounded this event.

PREVIOUS SIMILAR EVENTS

A review of events occurring within the past three years has not identified any previous similar occurrences.

COMMITMENTS

Those actions committed to by Progress Energy Carolinas, Inc. (PEC) in this document are identified below. Any other actions discussed in this submittal represent intended or planned actions by PEC. They are described for the NRC's information and are not regulatory commitments. Please notify the Manager – Support Services at BSEP of any questions regarding this document or any associated regulatory commitments.

- Preventive maintenance, exciter brush vibration monitoring, and trending program improvements are being developed and will be implemented by February 20, 2004.

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Exelon. Nuclear

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10 CFR 50.73

March 24, 2004

SVPLTR # 04-0009

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Dresden Nuclear Power Station, Unit 3
Facility Operating License No. DRP-25
NRC Docket No. 50-249

Subject: Licensee Event Report 2004-001-00, "Unit 3 Automatic Scram During Testing of the Main Turbine Master Trip Solenoid Valves"

Enclosed is Licensee Event Report 2004-001-00, "Unit 3 Automatic Scram During Testing of the Main Turbine Master Trip Solenoid Valves," for Dresden Nuclear Power Station. This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section."

Should you have any questions concerning this report, please contact Jeff Hansen, Regulatory Assurance Manager, at (815) 416-2800.

Respectfully,

DG Bost

Danny G. Bost
Site Vice President
Dresden Nuclear Power Station

Enclosure

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station

IE22

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OBM NO. 3150-0104 EXP 7-31-2004
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory information collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Dresden Nuclear Power Station Unit 3	05000249	1 of 4

4. TITLE Unit 3 Automatic Scram During Testing of the Main Turbine Master Trip Solenoid Valves

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME N/A	DOCKET NUMBER N/A
01	24	2004	2004	– 001 –	00	03	24	2004	FACILITY NAME N/A	DOCKET NUMBER N/A

9. OPERATING MODE	1
10. POWER LEVEL	096

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
	20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
George Papanic Jr.	(815) 416-2815

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	TG	SOL	G080	Y					

14. SUPPLEMENTAL REPORT EXPECTED			15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On January 24, 2004, at 0037 hours (CST), with Unit 3 at 96 percent power in Mode 1, an automatic scram occurred while performing the weekly surveillance of the Main Turbine Master Trip Solenoid Valves. The surveillance testing was performed in accordance with procedure DOS 5600-02, "Periodic Main Turbine, EHC and Generator Tests." The event was caused by a malfunction of the Main Turbine Master Trip Solenoid Valves, which resulted in the depressurization of the Emergency Trip Supply hydraulic header and the resulting momentary closure of the Main Turbine Stop Valves below 90 percent full open. The Reactor Protection System actuated as a result of the Main Turbine Stop Valve position and, as designed, automatically scrammed the reactor. The plant responded as expected to the automatic scram.

The root cause of the malfunction of the Main Turbine Master Trip Solenoid Valves was attributed to an improperly designed position switch rod and its associated housing by the Original Equipment Manufacturer, General Electric. The corrective actions to prevent reoccurrence are to replace the Main Turbine Master Trip Solenoid Valves with valves of a different design.

The safety significance of this event was minimal. All control rods fully inserted and all systems responded as expected to the automatic scram. There were no subsequent major equipment malfunctions.

1. FACILITY NAME	2. DOCKET NUMBER	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station Unit 3	05000249	2004	001	00	2 of 4

17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

Dresden Nuclear Power Station Unit 3 is a General Electric Company Boiling Water Reactor with a licensed maximum power level of 2957 megawatts thermal. The Energy Industry Identification System codes used in the text are identified as [XX].

A. Plant Conditions Prior to Event:

Unit: 03 Event Date: 01-24-2004 Event Time: 0037 CST
Reactor Mode: 1 Mode Name: Power Operation Power Level: 96 percent
Reactor Coolant System Pressure: 1000 psig

B. Description of Event:

Dresden Nuclear Power Station (Dresden) and other Exelon stations have been experiencing performance issues with their Main Turbine Master Trip Solenoid Valves (MTSVs) [TG] [SOL]. The cause of the poor solenoid performance was determined to be a "silting" phenomenon. General Electric (GE), the Original Equipment Manufacturer, was requested to evaluate the "silting" condition and find an alternate design to improve the solenoid performance. GE responded to this request by proposing the use of poppet solenoid MTSVs to replace the existing spool solenoid MTSVs. GE indicated that, unlike the spool valve, a poppet valve is not prone to stick due to its inherent design. The poppet solenoid valve has a line-contact on its seating surface verses a sliding surface contact with tight clearance tolerances on a spool solenoid valve.

GE successfully tested the poppet solenoid MTSVs. However, after completing the testing, GE modified the position switch on the original poppet solenoid valve assembly. This modification was done to eliminate the need of additional cables to power the position switch. The modified position switch was never tested on the test assembly. GE's evaluation concluded that the new poppet solenoid MTSV was a direct replacement for the currently used spool solenoid MTSV.

In September 2003, LaSalle County Station (LaSalle) was preparing for a Unit 2 outage and performed pre-installation testing of the poppet solenoid MTSVs. During pre-installation testing, LaSalle identified that the position switch on the poppet valve assembly was not functioning. GE suspected that the target area at the end of the switch rod was too small for it to function properly and decided to increase the target area of the switch. LaSalle returned the poppet solenoid MTSVs for switch modification and the poppet solenoid MTSVs were not installed.

In October 2003, Dresden performed pre-installation testing on the poppet solenoid MTSVs and found that the limit switch was still not functioning properly, even after the target area on the rod end had been increased based on the LaSalle experience. Further investigation revealed that the switch adapter material should have been stainless steel instead of carbon steel. GE agreed to make the adapter material change but additional testing following the change by GE was not performed.

On October 21, 2003, Dresden Unit 2 was in a refueling outage and the MTSVs were replaced with the poppet solenoid MTSVs. Post maintenance testing was performed satisfactorily without any problems.

On November 18, 2003, during weekly testing on Unit 3 per procedure DOS 5600-02, "Periodic Main Turbine, EHC and Generator Tests," MTSV "A" failed to trip. The cause of this MTSV failure to trip was determined to be "silting." Based on this, Dresden engineering recommended that the Unit 3 MTSVs be replaced with poppet solenoid MTSVs during the upcoming maintenance outage in December 2003.

On December 12, 2003, the Unit 3 MTSVs were replaced with poppet solenoid MTSVs. Post maintenance testing was performed with satisfactory results.

From November 2003 to January 23, 2004, Dresden Unit 2 successfully tested the poppet solenoid MTSVs during nine weekly on-line tests and Dresden Unit 3 successfully tested the valves during four weekly on-line tests.

On January 24, 2004, at 0037 hours (CST), with Unit 3 at 96 percent power in Mode 1, an automatic scram occurred while performing the weekly surveillance of the MTSVs. The surveillance testing was performed in accordance with applicable site procedures. The scram was caused by the momentary closure of the Main Turbine Stop Valves below 90 percent full open. The Reactor Protection System actuated as a result of the Main Turbine Stop Valve position and as designed, automatically scrammed the reactor. The plant responded as expected to the automatic scram.

An Emergency Notification System (ENS) call was made on January 24, 2004, at 0222 hours (CST) for the above-described event. The assigned ENS event number was 40474.

Post trip testing confirmed that the cause of the automatic scram was the result of the poppet solenoid MTSVs malfunctioning. Dresden decided to replace the Unit 3 poppet solenoid MTSVs with spool solenoid MTSVs. The decision was based in part on, the failure mode associated with the poppet solenoid MTSVs was not applicable to the spool solenoid MTSVs. The spool solenoid MTSVs are installed on all GE turbines of similar design to Dresden's turbine and, except for occasional sticking, the performance of the spool solenoid MTSVs has been satisfactory. The unit was synchronized to the grid on January 25, 2004 at 1324 hours (CST).

This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section." The automatic actuation of the reactor protection system is listed in 10 CFR 50.73(a)(2)(iv)(B).

Dresden Unit 2 is scheduled to replace its installed poppet solenoid MTSVs with the spool solenoid MTSVs during a maintenance outage. Dresden has completed an engineering evaluation that permits the suspension of MTSV testing until the MTSVs are replaced.

Additionally to resolve the "silting" issue, Dresden replaced the existing electro-hydraulic fluid with higher temperature rated synthetic fluid, cleaned the fluid reservoirs and replaced the filter cartridges with a different designed cartridge in October 2003 on Unit 2 and December 2003 on Unit 3.

C. Cause of Event:

The root cause of the malfunction of the poppet solenoid MTSVs was attributed to an improperly designed position switch rod and its associated housing by the Original Equipment Manufacturer, GE.

The two poppet solenoid MTSVs that were removed from Dresden Unit 3 and two poppet solenoid MTSVs that had not been installed were subjected to failure analysis testing. The failure analysis testing included response time testing, disassembly to inspect for foreign material and overall inspection of the internal valve components. The results of the testing were as follows.

- The poppet solenoid MTSVs were bench tested to determine if their response times were in the range of 40 to 60 millisecond. A high response time of the poppet valve is a concern as the poppet solenoid

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17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

MTSVs design momentarily ties the pressure and drain ports together. If the ports are tied together for a sufficient time, the Emergency Trip Supply hydraulic header will depressurize. One of the poppet solenoid MTSVs removed from Dresden Unit 3 had a response time of 200 milliseconds.

- An optical microscope inspection of the poppet solenoid MTSVs did not reveal any foreign material around the valve seat area. Additionally, the inspection found no indication of tearing or deterioration of the internal o-rings and backing rings.
- The overall visual inspection revealed that the internal position switch rod was bent on all four valves. Further examination revealed that the target could catch on threads within the switch housing. This defect would cause the observed delay in the response time of the valves.
- GE determined that the damage to the internal components most probably occurred during manufacturing.

The high response time of the poppet valves on Unit 3 caused the pressure and drain ports to be tied together for a sufficient time to cause the Emergency Trip Supply hydraulic header to depressurize and resulted in the momentary closure of the Main Turbine Stop Valves below 90 percent full open.

D. Safety Analysis:

The safety significance of this event was minimal. All control rods fully inserted and all systems responded as expected to the automatic scram. There were no subsequent major equipment malfunctions. Therefore, the consequences of this event had minimal impact on the health and safety of the public and reactor safety.

E. Corrective Actions:

The poppet solenoid MTSVs were replaced with spool solenoid MTSVs on Dresden Unit 3.

The poppet solenoid MTSVs will be replaced with the spool solenoid MTSVs during a scheduled maintenance outage on Dresden Unit 2.

An engineering evaluation was completed to permit the suspension of MTSV testing on Unit 2 until the poppet solenoid MTSVs are replaced with spool solenoid MTSVs.

F. Previous Occurrences:

A review of Dresden Nuclear Power Station Licensee Event Reports (LERs) and operating experience over the previous five years did not find any similar MTSV occurrences.

G. Component Failure Data:

GE poppet solenoid MTSV Part Number 378A3294P0001

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Exelon. Nuclear

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10 CFR 50.73

March 30, 2004

SVPLTR: #04-0013

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DRP-19 and DRP-25
NRC Docket Nos. 50-237 and 50-249

Subject: Licensee Event Report 2004-002-00, "Unit 3 Automatic Scram Due To Main Turbine Low Oil Pressure Trip and Subsequent Discovery of Inoperability of the Units 2 and 3 High Pressure Coolant Injection Systems"

Enclosed is Licensee Event Report 2004-002-00, "Unit 3 Automatic Scram Due To Main Turbine Low Oil Pressure Trip and Subsequent Discovery of Inoperability of the Units 2 and 3 High Pressure Coolant Injection Systems," for Dresden Nuclear Power Station. These events are being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section," and 10 CFR 50.73(a)(2)(v)(D), "Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident."

Should you have any questions concerning this report, please contact Jeff Hansen, Regulatory Assurance Manager, at (815) 416-2800.

Respectfully,

D. Bost

Danny G. Bost
Site Vice President
Dresden Nuclear Power Station

Enclosure
cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station

IE22

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED BY OBM NO. 3150-0104 EXP 7-31-2004

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
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4. TITLE Unit 3 Automatic Scram Due To Main Turbine Low Oil Pressure Trip and Subsequent Discovery of Inoperability of the Units 2 and 3 High Pressure Coolant Injection Systems

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME: Dresden Unit 2	DOCKET NUMBER: 05000237
01	30	2004	2004	002	00	03	30	2004	FACILITY NAME: N/A	DOCKET NUMBER: N/A

9. OPERATING MODE	1
10. POWER LEVEL	097

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
	20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)	X	50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)		50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
George Papanic Jr.	(815) 416-2815

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX

14. SUPPLEMENTAL REPORT EXPECTED			15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On January 30, 2004, at 1155 hours (CST), with Unit 3 at 97 percent power in Mode 1, an automatic scram occurred due to a Main Turbine trip from low lube oil pressure. The event occurred during a swapping of lube oil coolers. After the scram, reactor water level increased above the Reactor Feed Pump High Level trip set point. Reactor water level was subsequently restored to normal and the Reactor Feed Pumps were restarted.

On February 1, 2004, at 0400 hours (CST), subsequent investigations into the January 30, 2004, event determined that the High Pressure Coolant Injection Systems for Dresden Units 2 and 3 were inoperable. The inoperability was due to evaluations that determined that the Feedwater Level Control System would not maintain the post scram reactor water level below that which would prevent water from entering the High Pressure Coolant Injection System's turbine steam line.

The root cause of the automatic scram was inadequate procedural guidance for the swapping of Main Turbine lube oil coolers. The root cause of the High Pressure Coolant Injection System inoperability was low margin in the Feedwater Level Control System to accommodate changes to the post-scram vessel level response. The corrective action to prevent reoccurrence of the scram is to modify procedure DOP 5100-04, "Turbine Oil Cooler Operation." The corrective action to prevent reoccurrence of the High Pressure Coolant Injection Systems inoperability is to modify the post-scram response of the Feedwater Level Control System.

17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

Dresden Nuclear Power Station Units 2 and 3 are General Electric Company Boiling Water Reactors with a licensed maximum power level of 2957 megawatts thermal. The Energy Industry Identification System codes used in the text are identified as [XX].

A. Plant Conditions Prior to Event:

Unit: 03	Event Date: 1-30-2004	Event Time: 1155 CST
Reactor Mode: 1	Mode Name: Power Operation	Power Level: 97 percent

Reactor Coolant System Pressure: 1000 psig

B. Description of Event:

On January 30, 2004, the Shift Manager decided to swap the Unit 3 Main Turbine Lube Oil Coolers [TD] as the Turbine Oil Continuous Filter Differential Pressure had been increasing for several days. On January 30, 2004, at 1155 hours (CST), with Unit 3 at 97 percent power in Mode 1, an automatic scram occurred due to a Main Turbine trip from low lube oil pressure. The event occurred during a swapping of lube oil coolers. Immediately following the scram, the position of the Feedwater Regulating Valves (FRVs) [SJ] increased from 56 percent (%) open to 63 %. The increase in the position of the FRVs, combined with the post-scram decreasing reactor pressure, caused an increase in total feedwater flow that led to the trip of the "B" Reactor Feedwater Pump (RFP) [P] on low suction pressure. Additionally, subsequent FRVs response to increasing reactor vessel level was not fast enough to prevent the level from reaching the RFP High Level trip set point and resulted in the tripping of the "A" and "C" RFPs. Reactor water level was subsequently restored to normal and the RFPs were restarted. All rods inserted and other than the feedwater response, all other system responded as expected to the automatic scram.

An Emergency Notification System (ENS) call was made on January 30, 2004, at 1335 hours (CST) for the above-described scram event. The assigned ENS event number was 40491.

On February 1, 2004, at 0400 hours (CST), subsequent investigations into the January 30, 2004 event determined that the High Pressure Coolant Injection (HPCI) Systems [BJ] for Dresden Units 2 and 3 were inoperable. An evaluation by engineering determined that the Feedwater Level Control System (FWLCS) [SJ] would not maintain the post-scram reactor water level below that which would prevent water from entering the HPCI turbine steam line. Dresden Units 2 and 3 have separate HPCI nozzles in the reactor vessels that are located approximately 50 inches below the main steam nozzles. Technical Specification (TS) 3.5.1, "ECCS-Operating," requires HPCI operable in Modes 1, 2 and 3 with reactor steam dome pressure greater than 150 pounds per square inch gage (psig). At the time of discovery, Unit 2 was in Mode 1 and Unit 3 was in Mode 4.

An ENS call for Unit 2 was made on February 1, 2004, at 0854 hours (CST) for the above-described HPCI event. The assigned ENS event number was 40494.

The Units 2 and 3 FWLCS post-scram level setpoints were modified on February 2, 2004 and HPCI was declared operable. Unit 3 was synchronized to the grid on February 2, 2004, at 1813 hours (CST).

These events are being reported in accordance with:

- 10 CFR 50.73(a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section." The automatic actuation of the reactor protection system is listed in 10 CFR 50.73(a)(2)(iv)(B).

- 10 CFR 50.73(a)(2)(v)(D), "Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident." The HPCI is a single train system and the water was in the HPCI turbine steam line for approximately 20 minutes.

C. Cause of Event:

The root cause of the scram event was incorrect procedural guidance in Dresden Operating Procedure DOP 5100-04 "Turbine Oil Cooler Operation." The procedure directs the operator to stop filling the oncoming Main Turbine lube oil cooler prior to swapping. This caused air to be induced into the oncoming lube oil cooler from the hot lube oil volume being cooled by cold service water, and resulted in the Main Turbine trip from low lube oil pressure. This procedural guidance had been in place since 1991 and had been used approximately seven times since 1999. However, system realignment had only occurred once in the month of January.

The root cause of the HPCI inoperability was low margin in the FWLCS to accommodate changes to the post-scram vessel level response. The FWLCS is designed to respond to a scram by adjusting the vessel level set point from +30 inches to +5 inches and then after approximately 2 seconds, to lock the FRVs in place for approximately 15 seconds. After 15 seconds, the valve demand signal positions the FRVs at 30% of their previous position. At that time, the FWLCS reverts to controlling in the normal mode where the FRVs are positioned based on the rate of change in vessel level and the difference between the vessel level and the FWLCS set point.

Following the reactor scram on January 30, 2004, the following occurred.

- The position of the FRVs immediately increased from 56% open to 63% open during the approximately 2 seconds it takes for the FWLCS to lock the FRVs in place for 15 seconds. During this period, the increase in the position of the FRVs, combined with decreasing reactor pressure, caused an increase in total feedwater flow that led to the trip of the "B" RFP on low suction pressure. A RFP had not tripped on previous similar scrams, as the similar scrams occurred prior to the need to operate with 3 RFPs at full power.

- The FRVs began to close from 63% open at approximately 16 seconds after the scram signal due to the pulse down signal from the FWLCS to reposition the FRVs to 30% of their previous position. The FRVs never reached 30% of the previous position because at 24 seconds after the scram, FWLCS signaled the valves to reopen. At approximately 30 seconds after the scram signal the FWLCS signaled the FRVs to close. However, the rate at which the FRVs closed was not fast enough to prevent overfilling the vessel, tripping the "A" and "C" RFPs on high water level, and putting water into the HPCI steam supply line.

The FWLCS operated as designed during this event. The condition that the FWLCS had low margin to accommodate changes to the post-scram vessel level response was not known prior to this event because no analytical model capable of predicting the dynamic interaction between the FWLCS and other factors affecting vessel level was available. This resulted in the failure to adequately evaluate or test the post-scram response of the FWLCS prior to implementation of 3 RFP operation.

The immediate corrective actions for Units 2 and 3 were to lower the FWLCS post-scram vessel level set point from +5 inches to –10 inches. These set point changes provide reasonable assurance that a vessel overfill event will not recur.

1. FACILITY NAME	2. DOCKET NUMBER	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station Unit 3	05000249	2004	002	00	4 of 5

17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

The corrective action to prevent reoccurrence is to re-design the FWLCS post-scram response. Exelon Engineering will develop a dynamic model capable of accurately predicting the response of the FWLCS. This model will be benchmarked against the two most recent scrams and used to optimize the re-design. The modifications to install the improved FWLCS design will be implemented if necessary, during the next refueling outage of each unit or outage of sufficient duration after the development of the analytical model to predict the interaction of the FWLCS and post scram vessel level response.

D. Safety Analysis:

The safety significance of the scram event was minimal. All control rods fully inserted and other than the feedwater response, all systems responded as expected to the automatic scram.

The safety significance of the HPCI inoperability event was minimal. For Dresden Units 2 and 3, 2 transients and 2 design basis accidents have the potential for water carryover into the HPCI steam line and assume the availability of the HPCI for redundant long term inventory make-up. For these events, a conservative analysis has been performed using Automatic Depressurization System and low pressure Emergency Core Cooling Systems as an alternate core cooling sequence that demonstrates there is a substantial margin to predicted cladding perforation.

Therefore, the consequences of these events had minimal impact on the health and safety of the public and reactor safety.

E. Corrective Actions:

Procedure DOP 5100-04 has been revised.

The immediate corrective actions for Units 2 and 3 were to lower the FWLCS post-scram level set point from +5 inches to –10 inches.

Exelon will develop an analytical model to predict the interaction of the FWLCS and post scram vessel level response and if necessary, the FWLCS post-scram response will be modified.

F. Previous Occurrences:

A review of Dresden Nuclear Power Station Licensee Event Reports (LERs) and operating experience over the previous five years did not find any similar occurrences associated with the Main Turbine Lube Oil Coolers.

A review of Dresden Nuclear Power Station LERs identified that the most recent LER associated with the FWLCS and a reactor vessel high water level was LER 98-003-00, "Reactor Scram Results from MSIV Closure Caused by a Spurious Group 1 Isolation Signal due to Inadequate Preventive Maintenance." Following the scram, a feedwater transient occurred which resulted in water entering the HPCI steam supply line. The LER corrective actions included modifications to the FWLCS. The actions were successful in preventing water from entering the HPCI steam supply line during subsequent similar scram events when the plant was operated with 2 RFPs.

G. Component Failure Data:

NA

16

Exelon. Nuclear

Exelon Generation Company, LLC
Dresden Nuclear Power Station
6500 North Dresden Road
Morris, IL 60450-9765

www.exeloncorp.com

10 CFR 50.73

July 6, 2004

SVPLTR: #04-0045

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DRP-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Subject: Licensee Event Report 2004-003-00, "Unit 3 Scram Due to Loss of Offsite Power and Subsequent Inoperability of the Standby Gas Treatment System for Units 2 and 3"

Enclosed is Licensee Event Report 2004-003-00, "Unit 3 Scram Due to Loss of Offsite Power and Subsequent Inoperability of the Standby Gas Treatment System for Units 2 and 3," for Dresden Nuclear Power Station. This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section," and 10 CFR 50.73(a)(2)(i)(B), "Any operation or condition which was prohibited by the plant's Technical Specifications."

Should you have any questions concerning this report, please contact Jeff Hansen, Regulatory Assurance Manager, at (815) 416-2800.

Respectfully,

David B Wozniak for/

Danny G. Bost
Site Vice President
Dresden Nuclear Power Station

Enclosure
cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station

IE22

NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OBM NO. 3150-0104 EXP 7-31-2004
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory information collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Dresden Nuclear Power Station Unit 3	05000249	1 of 4

4. TITLE Unit 3 Scram Due to Loss of Offsite Power and Subsequent Inoperability of the Standby Gas Treatment System for Units 2 and 3

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Dresden Unit 2	05000237
05	05	2004	2004	– 003	00	07	06	2004	FACILITY NAME N/A	DOCKET NUMBER N/A

9. OPERATING MODE	1
10. POWER LEVEL	100

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

	20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)
	20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)
	20.2203(a)(1)		50.36(c)(1)(i)(A)	X	50.73(a)(2)(iv)(A)		73.71(a)(4)
	20.2203(a)(2)(i)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)
	20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)		
	20.2203(a)(2)(iv)		50.73(a)(2)(i)(A)		50.73(a)(2)(v)(D)		
	20.2203(a)(2)(v)	X	50.73(a)(2)(i)(B)		50.73(a)(2)(vii)		
	20.2203(a)(2)(vi)		50.73(a)(2)(i)(C)		50.73(a)(2)(viii)(A)		
	20.2203(a)(3)(i)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)		

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
George Papanic Jr.	(815) 416-2815

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
X	FK	BRK	I005	N					

14. SUPPLEMENTAL REPORT EXPECTED			15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		10	30	2004

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On May 5, 2004, at 1327 hours (CDT), with Unit 3 at 100 percent power in Mode 1, an automatic scram occurred due to a Main Generator Load Reject when a loss of offsite power occurred. The Emergency Diesel Generators automatically started and powered their respective electrical busses. All control rods fully inserted and Group I, II and III isolations occurred as expected. Operations personnel manually initiated the Isolation Condenser System for reactor pressure control, the High Pressure Coolant Injection System for reactor water level control, and the Low Pressure Coolant Injection System for Torus cooling. All systems initially responded to the scram as expected except the Standby Gas Treatment System was unable to maintain the Secondary Containment at the Technical Specification Surveillance Requirement limit of greater than or equal to 0.25 inches of vacuum water gauge. An Unusual Event for the loss of offsite power was declared at 1342 hours (CDT) and terminated at 1601 hours (CDT) on May 5, 2004. Additionally, during restoration of offsite electrical power to Bus 33, the Emergency Diesel Generator 2/3 output electrical breaker tripped.

The root causes associated with the load reject and loss of offsite power and the low Secondary Containment vacuum were respectively, equipment failure in the "C" phase of the 345 kilovolt circuit breaker 8-15 and a degraded Secondary Containment boundary not detected due to an inadequate leak rate test procedure. The cause of the Emergency Diesel Generator output breaker trip remains under investigation.

1. FACILITY NAME	2. DOCKET NUMBER	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station Unit 3	05000249	2004	003	00	2 of 4

17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

Dresden Nuclear Power Station (DNPS) Units 2 and 3 are a General Electric Company Boiling Water Reactor with a licensed maximum power level of 2957 megawatts thermal. The Energy Industry Identification System codes used in the text are identified as [XX].

A. Plant Conditions Prior to Event:

Unit: 03 | Event Date: 5-5-2004 | Event Time: 1327 CDT
Reactor Mode: 1 | Mode Name: Power Operation | Power Level: 100 percent
Reactor Coolant System Pressure: 1000 psig

B. Description of Event:

On May 5, 2004, electrical breaker switching was being performed in the DNPS switchyard to support the testing of a 345 kilovolt (kv) offsite electrical line. A loss of offsite power (LOOP) occurred to Unit 3 when 345 kv breaker 8-15 [BKR] located in the switchyard [FK] was opened.

On May 5, 2004, at 1327 hours (CDT), with Unit 3 at 100 percent power in Mode 1, an automatic scram occurred due a Main Generator Load Reject when the LOOP occurred. The Emergency Diesel Generators (EDGs) [DG] automatically started and powered their respective electrical busses. All control rods fully inserted and Group I, II and III isolations occurred as expected. Operations personnel manually initiated the Isolation Condenser System [BL] for reactor pressure control, High Pressure Coolant Injection System [BJ] for reactor water level control, and Low Pressure Coolant Injection System [BO] for Torus cooling. All systems initially responded as expected to the scram except for the Standby Gas Treatment System (SGT) [BH] that was unable to maintain the Secondary Containment at the Technical Specification Surveillance Requirement limit of greater than or equal to 0.25 inches of vacuum water gauge. Secondary containment was declared inoperable for Units 2 and 3.

An Unusual Event for the LOOP was declared at 1342 hours (CDT). An ENS call was made at 1429 hours (CDT) for the above-described event. The assigned ENS event number was 40727.

At 1558 hours (CDT), the EDG 2/3 output electrical breaker tripped on reverse power during restoration of offsite electrical power to Bus 33 that was being fed from EDG 2/3. Bus 33 remained powered from the offsite source.

The Unusual Event was terminated at 1601 hours (CDT) when offsite power was restored to Unit 3.

At 1630 hours (CDT), SGT was declared operable when the Secondary Containment pressure was restored to greater than 0.25 inches of vacuum water gauge.

This event is being reported in accordance with:

- 10 CFR 50.73(a)(2)(iv)(A), "Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section," and
- 10 CFR 50.73(a)(2)(i)(B), "Any operation or condition which was prohibited by the plant's Technical Specifications."

1. FACILITY NAME	2. DOCKET NUMBER	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station Unit 3	05000249	2004	003	00	3 of 4

17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

These events are addressed in the NRC Special Inspection Report Number 05000249/2004009 dated June 21, 2004.

C. Cause of Event:

The root causes associated with the load reject and LOOP and the low Secondary Containment vacuum were respectively, equipment failure in the "C" phase of the 345 kv circuit breaker 8-15 and a degraded secondary containment boundary not detected due to an inadequate leak rate test procedure. The cause of the EDG output breaker trip is still under investigation.

The equipment failure of the 345 kv circuit breaker 8-15 circuit breaker occurred due to age-related and application related degradation. The vendor, prior to the event, did not provide information to Exelon Corporation, a product advisory issued in July 2003, regarding the possibility of breaker slow operation or failure to operate. This is applicable to circuit breakers 8-15 and 6-7. The corrective action to prevent reoccurrence is to revise the preventative maintenance procedure governing both circuit breakers 8-15 and 6-7 to implement the product advisory recommendations.

The degraded secondary containment boundary resulted from air in-leakage into the Unit 2 Drywell and Torus Purge Exhaust (DTPE) filter housings. At the time of the event, Unit 2 was in a maintenance outage and the DTPE fans were in operation due to activities in the Unit 2 drywell. The DTPE fans are not normally in operation and the secondary containment leak rate test procedure does not test with the DTPE fans operating as a part of the secondary containment barrier. Two corrective actions to prevent reoccurrence are being taken:

The first is to modify the current design to trip the DTPE fans on both units following an automatic SGT system initiation from either unit, rather than operate the DTPE fans during the secondary containment leak rate test. The second action is to develop a source document that clearly identifies the secondary containment boundaries.

D. Safety Analysis:

The safety significance of the LOOP event was minimal. All systems initially responded as expected to the scram except for the SGT system that was unable to maintain the secondary containment at the Technical Specification Surveillance Requirement limit of greater than or equal to 0.25 inches of vacuum water gauge. However, secondary containment was maintained at a negative pressure at all times during the event. The EDGs were supplying power to their respective busses, as designed, and offsite power was availiable through Unit 2.

Therefore, the consequences of this event had minimal impact on the health and safety of the public and reactor safety.

E. Corrective Actions:

345 kv circuit breaker 8-15 was repaired and a vendor upgrade kit was installed. The circuit breaker upgrade kit will be installed on circuit breaker 6-7 at the next availiable opportunity.

The preventive maintenance procedure for circuit breakers 8-15 and 6-7 will be revised to incorporate appropriate vendor advisory recommendations.

DNPS procedures were revised to require the securing of the DTPE Fans upon initiation of SGT.

The DTPE filter housing in-leakage has been repaired to correct air inleakage.

The SGT initiation logic will be changed to include the tripping of the DTPE Fans for both units.

1. FACILITY NAME	2. DOCKET NUMBER	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station Unit 3	05000249	2004	003	00	4 of 4

17. NARRATIVE (If more space is required, use additional copies of NRC Form 366A)

The final corrective actions to prevent reoccurrence for the Emergency Diesel Generator output breaker will be described in a supplemental report scheduled to be submitted no later than October 30, 2004.

F. Previous Occurrences:

A review of Dresden Nuclear Power Station Licensee Event Reports (LERs) and operating experience identified the following LER.

Unit 3 LER 89-001-01 described a March 25, 1989, event in which an electrical fault in the 345 kilovolt circuit breaker 8-15 phase A internal ground capacitor and slow transfer of the 4 kv Bus 32 from transformer 32 to 31 caused a LOOP for Unit 3. The corrective actions included the removal of the internal ground capacitors from 345 kilovolt circuit breaker 8-15.

G. Component Failure Data:

I.T.E. Power Circuit Breaker, Model C Type GA

17

VERMONT YANKEE NUCLEAR POWER CORPORATION

P. O. BOX 157
GOVERNOR HUNT ROAD
VERNON, VERMONT 05354

April 12, 1991
VYV # 91-104

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

REFERENCE: Operating License DPR-28
Docket No. 50-271
Reportable Occurrence No. LER # 91-05

Dear Sirs:

As defined by 10 CFR 50.73, we are reporting the attached Reportable Occurrence as LER # 91-05.

Very truly yours,

VERMONT YANKEE NUCLEAR POWER CORPORATION

Robert J Wanczyk
for Donald A. Reid
Plant Manager

cc: Regional Administrator
USNRC
Region I
475 Allendale Road
King of Prussia, PA 19406

IE22
1/1

NRC Form 366 U.S. NUCLEAR REGULATORY COMMISSION
(6-89)

APPROVED OMS NO.3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NO. (2)	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	0 1 OF 0 4

TITLE (4)
Reactor Scram due to Mechanical Failure of 345KV Switchyard Bus caused by Broken High Voltage Insulator Stack

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ. #	REV#	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NO.(S)
0 3	1 3	9 1	9 1	- 0 0 5	- 0 0	0 4	1 2	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10CFR §: ✓ ONE OR MORE (11)			
POWER LEVEL (10)	1 0 0	[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
		[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
		[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER:
		[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
		[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
		[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NO. (AREA CODE)
DONALD A. REID, PLANT MANAGER	8 0 2 2 5 7 - 7 7 1 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYST	COMPNT	MFR	REPORTABLE TO NPRDS	CAUSE	SYST	COMPNT	MFR	REPORTABLE TO NPRDS
X	F K	I N S	U 0 8 5	N	N/A				
N/A					N/A				

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MO	DA	YR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approx. fifteen single-space typewritten lines) (16)

On 3/13/91 at 2228 hours, with reactor power at 100%, a Reactor scram occurred due to a generator/turbine trip as a result of the failure of an 80 ft. vertical section of 345KV Switchyard Bus (B Phase) between the Main Transformer aerial T1 disconnect switch and the horizontal bus bar spanning the 1T-11 and 81-1T-2 disconnect switches. The cause of the bus failure is attributed to a broken insulator stack which secured the bus to the tower. The plant was subsequently stablized by resetting Primary Containment isolations, restarting Reactor Water Cleanup and establishing level control using the 10% Feedwater Regulator valve. Shutdown Cooling was later employed at 0504 hours on 3/14/91 and maintained until the necessary repairs and testing were completed. The reactor was returned to critical on 3/18/91 at 0055 hours. The need to expand present Switchyard system maintenance is being evaluated.

UTILITY NAME (1)	DOCKET NO. (2)	LER NUMBER (6) YEAR		SEQ. #		REV#	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1	-	0 0 5	-	0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A) (17)

DESCRIPTION OF EVENT

On 3/13/91 at 2228 hours, during normal operation with Reactor power at 100%, a Reactor scram occurred as a result of a turbine trip on Generator Load Reject due to a 345KV Switchyard Tie Line Differential Fault. During the first 14 seconds of the event, the following automatic system responses occurred without Operator intervention:

a. Trip of Tie Line breakers 1T and 81-1T.
b. Fast Transfer of 4KV Buses and 1 and 2 to the Startup transformers.
c. Reactor scram on Turbine Control Valve Fast Closure signal.
d. Primary Containment Isolation System (PCIS)(JM*) Initiation, Groups 2, and 3 on Reactor Vessel "Lo" water level.

Operations personnel responded to the scram by implementing the required steps delineated in Emergency Operating Procedure OE-3100 "Scram Procedure" which governs reactor operation in a post-scram environment.

Automatic system responses a) thru c) were anticipated as a result of the 345KV Tie Line Fault. The Primary Containment Isolation System (PCIS) initiations experienced subsequent to the turbine trip were in response to the characteristic drop in Reactor water level from vessel void collapse. Vessel level, which initially dropped to a 120 inch level from the void collapse, quickly recovered with the "A" and "C" Reactor Feedwater pumps running. In an effort to control the increasing level, the "C" Reactor Feedwater pump was secured by Operations personnel. At 2230 hours (2 minutes into the event), the "A" Reactor Feedwater pump tripped on High Reactor water level (177 inches).

At 2231 hours, the Reactor scram was reset and the plant subsequently stabilized in Hot Standby by: restarting Reactor Water Cleanup; resetting PCIS Group 2, 3, and 5 isolations and establishing level control using the 10% Feedwater Regulator valve.

At 2235 hours, operators received a report from Security that a large flash had been observed in the Switchyard just prior to the Reactor scram. The local Fire Department was notified, but no fire ensued. The flash that had been observed was an electrical arc resulting from the connection break of the "B" phase.

At 2356 hours, Reactor depressurization and cooldown began using the Main Condenser and the Bypass Opening Jack. At 0504 hours on 3/14/91, RHR Shutdown Cooling was established on the "B" RHR loop.

*Energy Information Identification System (EIIS) Component Identifier

UTILITY NAME (1)	DOCKET NO. (2)	LER NUMBER (6) YEAR		SEQ. #		REV#	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1	-	0 0 5	-	0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A) (17)

DESCRIPTION OF EVENT (Contd.)

The reactor was returned to critical on 3/18/91 at 0055 hours.

During the course of the event, the following additional anomalies occurred:

a) Turbine Pressure Control switched from Electrical regulation to Mechanical regulation which remained in effect during Reactor cooldown.

b) AOG "A" and "B" Train Recombiners tripped and isolated. The "B" Recombiner was reset and returned to service.

c) RPS Alternate Power Supply breakers from MCC 8B tripped. The breakers were subsequently manually reset.

d) Spurious Reactor and Turbine Area Radiation alarms were received during the event. The alarms were subsequently cleared and did not return.

e) The PCIS group 2A, 3A, 5A and 5B (RWCU) isolation signals occurred within one second of the trip. These isolations were expected to occur after the low water level trip 8.5 seconds into the event.

An analysis of the above events was performed. Recorded data confirmed that the above equipment/circuitry responses occurred coincident with the Switchyard Fault. A review of recorded bus voltage data for buses supplying the above equipment and circuitry revealed that 4 separate voltage dips on the buses had occurred during the fault. These voltage dips were concluded significant enough to cause the equipment responses experienced, which in each case, the equipment had Undervoltage features or Seal-In circuitry.

An inspection of the Switchyard was performed immediately after the event which revealed the lower section of "B" Phase bus bar to be broken off at the lower horizontal bus bar attachment point. (Reference attached pictorial.) The upper insulator stack and T connector which served as a tie point for the lower and upper bus bar sections was observed broken between the third and fourth insulators with the fourth insulator and T connector still attached to the buswork. During the course of inspections the next morning (on 3/14/91), a gust of wind caused the hanging bus work to break off at the T-1 disconnect switch jaw and fall to the ground. No additional Switchyard damage occurred from the falling bus.

CAUSE OF EVENT

The root cause of the Switchyard bus failure is attributed to a failed insulator support between the bus and the tower. The lower insulator stack, which is comprised of four insulators coupled together, broke away from the tower at the base of the first insulator. This caused a swinging moment arm developing a force on the bus connector at the opposite end of the insulator. The excessive force snapped the vertical bar out of the welded socket on the horizontal bus bar. This resulted in an open circuit in "B" Phase and a "B" to "C" Phase flashover as the bus swung past the "C" Phase vertical bus bar. The combination of these two events initiated the Tie Line Differential Protective Relaying.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A) (17)

ANALYSIS OF EVENT

The events detailed in this report did not have adverse safety implications.

1. The Tie Line Differential Protective Relaying operated as designed which initiated the generator trip and Fast Transfer of plant buses to the Startup transformers.

2. The Reactor Protective System operated as designed and scrammed the reactor after receiving a Turbine Control Valve fast closure signal.

3. All other safety system responded as expected.

CORRECTIVE ACTIONS

IMMEDIATE CORRECTIVE ACTIONS

1. Immediate corrective actions included recovering from the Reactor scram utilizing appropriate plant procedures.

2. Efforts were immediately initiated to repair the "B" and "C" phase vertical bus work. A visual and thermography inspection was conducted of the entire Switchyard to identify any additional trouble spots. An additional insulator on the "A" Phase was found with arc damage and subsequently replaced.

3. The Main and Auxiliary transformers were Doble tested and oil samples were taken to assess any damage which might have been caused by the Switchyard fault. No anomalies or degradation were found. The fault effects on the transformers were analyzed and determined to be bounded by the design.

LONG TERM CORRECTIVE ACTIONS

1. The plant will meet with VELCO (Vermont Electric Power Co., Inc.) and evaluate the adequacy of the Switchyard Maintenance Program.

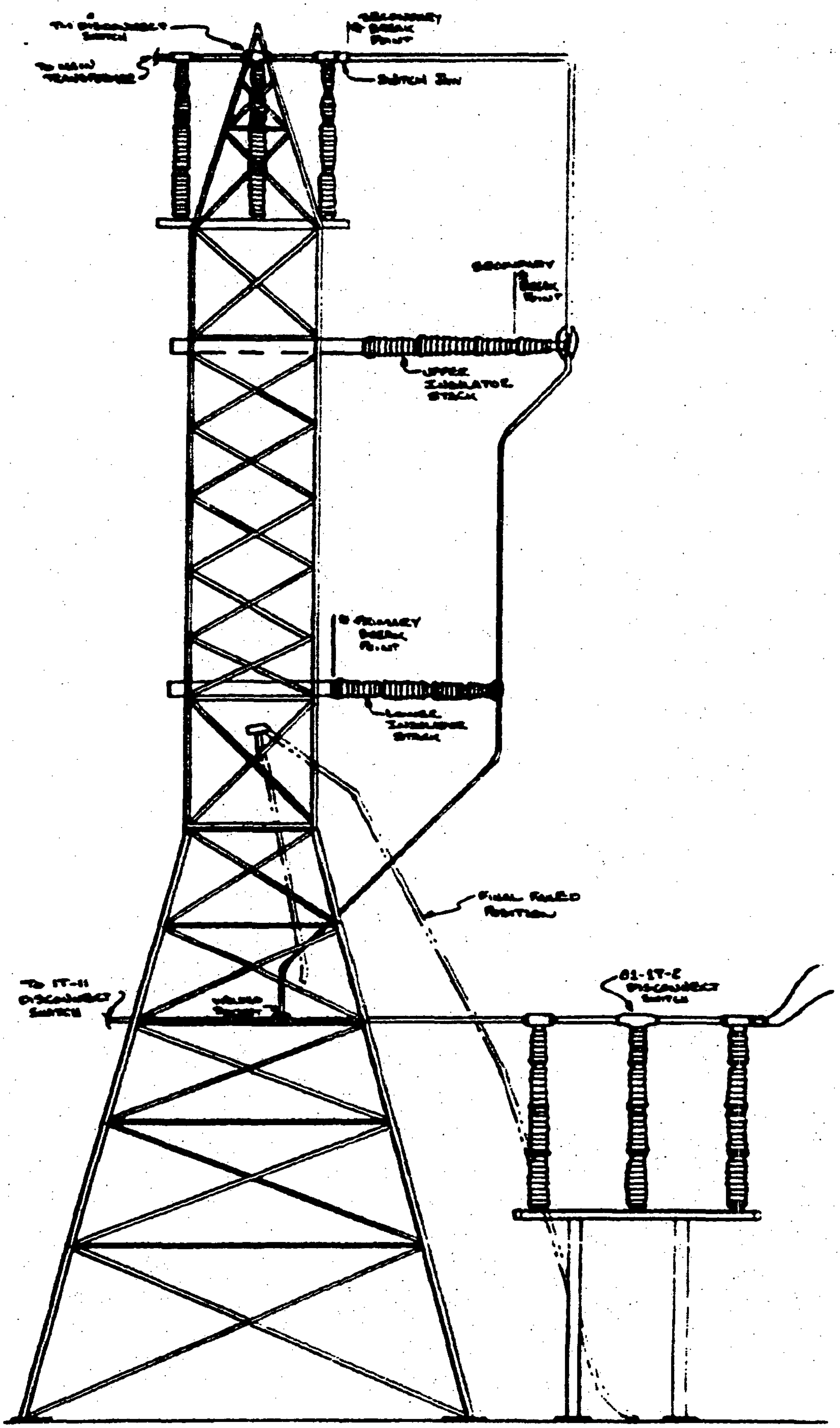
2. The failed insulator has been returned to the manufacturer for analysis and recommendations.

3. A detailed engineering analysis of the Switchyard vertical buswork will be performed to determine the adequacy of the present mounting configuration.

The above long term corrective actions are expected to be completed by 12/31/91. Based upon analysis results and findings, additional corrective actions will be initiated as appropriate.

ADDITIONAL INFORMATION

There have been no similar events of this type reported to the Commission in the past five years.


UPPER
INSULATOR
STACK
FINAL FAILED
POSITION

18

VERMONT YANKEE NUCLEAR POWER CORPORATION

P.O. Box 157 Governor Hunt Road
Vernon, Vermont 05354-0157
802-257-

June 6, 1991
VYV # 91-135

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

REFERENCE: Operating License DPR-28
Docket No. 50-271
Peportable Occurrence No. LER 91-09

Dear Sirs:

As defined by 10 CFR 50.73, we are reporting the attached Reportable Occurrence as LER 91-09.

This report was originally scheduled for submittal on 05/23/91. However, a two week extension was granted on 05/22/91 by R. Barkley, Acting Section Chief, Reactor Projects 3A (via T. Hiltz, NRC Resident Engineer at Vermont Yankee).

Very truly yours,

VERMONT YANKEE NUCLEAR POWER CORPORATION

Robert J Wanczyk
for Donald A. Reid
Plant Manager

cc: Regional Administrator
USNRC
Region I
475 Allendale Road
King of Prussia, PA 19406

IE22

NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMS NO.3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

LICENSEE EVENT REPORT (LER)

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TITLE (4)
Reactor Scram Due to Loss of Normal Off-site Power (LNP) Caused By Inadequate Procedure Guideline

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ. #	REV#	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NO.(S)
										0 5 0 0 0
0 4	2 3	9 1	9 1	- 0 0 9 -	0 0	0 5	2 3	9 1		0 5 0 0 0

OPERATING MODE (9): N
POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10CFR §: ✓ ONE OR MORE (11)

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER:
[ ] 20.405(a)(1)(iii)	[X] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NO. AREA CODE	
DONALD A. REID, PLANT MANAGER	8 0 2	2 5 7 - 7 7 1 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYST	COMPNT	MFR	REPORTABLE TO NPRDS	CAUSE	SYST	COMPNT	MFR	REPORTABLE TO NPRDS
X	F K	B Y C	E 3 5 3	N	N/A				
X	F K	2 4	W 3 5 1	N	N/A				

SUPPLEMENTAL REPORT EXPECTED (14)

[X] YES (If yes, complete EXPECTED SUBMISSION DATE) [ ] NO

EXPECTED SUBMISSION DATE (15): MO 0 8 DA 3 0 YR 9 1

ABSTRACT (Limit to 1400 spaces, i.e., approx. fifteen single-space typewritten lines) (16)

On 04/23/91 at 1448 hours, during normal operation with Reactor power at 100%, a Reactor Scram occurred as a result of a Generator/Turbine trip on Generator Load Reject due to the receipt of a 345KV Breaker Failure Signal. The Failure Signal was the result of Breaker Failure Interlock (BFI) signals that occurred simultaneously in the 345KV and 115KV Breaker control circuitry during the restoration of a battery bank to Switchyard Bus DC 4A. The cumulative effects of both (BFI) signals resulted in a total loss of 345KV and 115KV off-site power. An Unusual Event was declared at 1507 hours. Both Emergency Diesel Generators provided power for essential safety related systems during the LNP until approximately 0430 hours on 04/24/91 at which point off-site 345KV power was restored and backfed through the Station Auxiliary Transformer. During the event, Torus Water volume exceeded the Technical Specification limit of 70,000 cubic ft. The Unusual Event was terminated at 1950 hours on 04/24/91. The reactor reached Cold Shutdown at 0357 hours on 04/25/91 and was returned to critical at 0300 hours on 04/30/91. The Root Cause of this event is failure of the repair department personnel to recognize the consequences of operating a DC bus without a connected battery bank. Corrective Actions to prevent reoccurence are presently being finalized and will be presented in a supplemental report.

DESCRIPTION OF EVENT

On 04/23/91 at 1448 hours, during normal operation with Reactor power at 100%, a Reactor scram occurred as a result of a Generator/Turbine trip on Generator Load Reject due to the receipt of a 345KV Breaker Failure Signal. The 345KV Breaker Failure Signal was received as a result of Breaker Failure Interlock (BFI) signals that occurred simultaneously in the 345KV Breaker 81-1T and 115 KV Breaker K-1 control circuitry.

The (BFI) signal from 115KV Breaker K-1 initiated the following automatic system responses:

- Opening of 115KV Breaker K-186
- Opening of 345KV Breakers 379 and 381

The loss of 381 and 379 breakers removed all power sources to the Auto Transformer which in conjunction with the K186 trip resulted in a total loss of 115KV power.

The (BFI) signal from 345KV Breaker 81-1T initiated the following automatic system responses:

- Generation of 345KV Breaker Failure Signal
- Opening of 345KV Breakers 381 and 1T
- Lockout of Main Generator 86GP and 86GB relays, causing the Main Generator and Exciter Field breakers to open

The Generator Primary and Backup Lockout relays initiated the following automatic system responses:

- Main Turbine Trip
- Opening of 345KV Breaker 81-1T and Northfield Line trip at Northfield
- Attempted Fast Transfer of 4KV Buses 1 and 2 to the Startup Transformers but 115KV power was unavailable

The cumulative effects of both (BFI) signals resulted in a total loss of 345KV and 115KV off-site power. However, an additional off-site power source was available through the Vernon Hydro Station Tie line. The 4KV Hydro station output, which is designated as a delayed access off-site power source, was available throughout the event.

Prior to the event, the plant was in the process of completing the replacement of Switchyard Battery Bank 4A in accordance with a Maintenance Department guideline. All work with the exception of restoring the connection of the battery bank to the DC 4A bus, was completed without incident. While performing the final sequence of actions necessary to reconnect the battery bank to DC Bus 4A, a DC voltage transient occurred on the bus which initiated the event.

TEXT (If more space is required, use additional NRC Form 366A) (17)

DESCRIPTION OF EVENT (cont.)

During the first second of the event (1448:29 hours), as a result of the inablility to reenergize 4KV buses 1 and 2 from Fast Transfer to the Startup transformers, all station loads fed from these buses were lost. Major system responses to the loss of the power included the trip of Reactor Protection System (RPS)(*JC) "A" and "B" MG sets and receipt of Primary Containment Isolation Signals (PCIS)(*JM) Groups 1, 2, 3 and 5 resulting in the required closure of PCIS Groups 1, 2, and 3 isolation valves. (Motor operated valve closures within these Groups occurred after Emergency Diesel Generator power was supplied to the respective buses).

The loss of all power on 4KV Buses 1 thru 4 initiated the opening of Tie breakers 3T1 and 4T2 to provide isolation of Safety Buses 3 and 4 which, in the event of normal power loss, are aligned with the station Emergency Diesel Generators. An autostart of both diesels followed which reenergized Bus 3 and Bus 4 at 1448:45 hours. Both diesels remained in operation without incident until approximately 0430 hours on 04/24/91 at which time off-site 345KV power was restored and backfed through the Station Auxiliary Transformer.

In response to the Scram, Operation personnel entered Emergency Operating Procedure OE 3100, "Scram Procedure" which governs reactor operation in a post-scram environment. Immediate actions initiated at 1450 hours by Operations personnel to stabilize Reactor pressure and level included the manual lifting of Safety Relief Valve (SRV)-A, the manual initiation of High Pressure Coolant Injection System (HPCI)(*BJ), and startup of both RHR loops in the Torus Cooling mode. Both RPS MG sets were successfully restarted and RPS buses reenergized at 1515 hours. The initial scram was reset at 1533 hours.

During the period from 1450 hours on 04/23/91 to 1346 hours on 04/24/91, the combination of HPCI and Reactor Core Isolation Cooling (RCIC) (*BN) systems and SRV's were manually employed in accordance with procedure OE 3100 to control Reactor pressure level. The first use of RCIC system began at 1645 hours on 04/23/91. During the above 23 hour period, several additional events transpired. The following is a summary and discussion of those events:

* Energy Information Identification System (EIIS) component Identifier

DESCRIPTION OF EVENT (cont.)

A. Reactor Scrams on "Lo" Reactor Water Level were experienced at 1534 hours and 2112 hours on 04/23/91.

The first Scram occurred due to low Reactor water level during the process of securing HPCI and transferring to RCIC. Prior to the scram, reactor pressure and level had been steadily decreasing during the first 30 minutes of HPCI operation which prompted a change in cooling systems by Operations personnel. During the process of securing HPCI, Reactor Water level continued to decline to the 132 inch "Lo" level setpoint which initiated the Reactor scram. PCIS - Groups 2, 3, and 5 isolations which would normally initiate on "Lo" Reactor water level were already present from the initial Scram at 1448 hours. After receiving the Scram, Operations personnel completed the transfer to RCIC for level and pressure control. Reactor pressure and level recovered after RCIC initiation. The Scram and PCIS Groups 2, 3, and 5 isolations were subsequently reset at 1548 hours.

The second Scram resulted as a momentary drop in water level was experienced due to level shrink resulting from an increase in Reactor pressure experienced after cycling SRV-D. Water level dropped to approximately 112 inches during the pressure surge. The initiation of PCIS Groups 2, 3, and 5 logic occurred coincident with the level drop as required. The scram was subsequently reset at 2127 hours. PCIS Groups 2 and 5 logic were reset at 2128 hours and Group 3 logic later reset at 2154 hours.

B. Emergency Operating Procedure OE 3104, "Torus Temperature and Level Control Procedure", was entered at 1533 hours and 2112 hours on 04/23/91 due to Torus water volume exceeding the Technical Specification limit of 70,000 cubic ft.

In both occurrences, actions were taken in accordance with OE 3104 to reduce Torus water volume. Water reduction actions undertaken after the first entry into OE 3104 were successful and Torus water volume was reduced and maintained below 70,000 cubic ft. Later in the event, at 2112 hours, Torus water volume was not able to be maintained below 70,000 cubic ft. This resulted in the entry into the Technical Specification, "Required Cold Shutdown in 24 Hour" requirement. Due to the volume limitations of Torus water being processed through Radwaste, the Torus volume remained above 70,000 cubic ft. until 1925 hours on 04/24/91. The Technical Specification cold shutdown requirement and OE 3104 were excited at this time.

C. RCIC tripped on overspeed at 1904 hours on 04/23/91. The overspeed trip was reset at 1912 hours and operation of the system resumed.

* Energy Information Identification System (EIIS) Component Identifier

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMS NO.3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A) (17)

DESCRIPTION OF EVENT (cont.)

The trip is attributed to an operator error in the adjustment of the RCIC Flow Controller prior to switching from the MANUAL to AUTO mode.

D. The "A" Station Air Compressor tripped at 1542 hours on 04/23/91 due to inadequate Service Water cooling flow. A reserve diesel air compressor was subsequently connected to the outlet of the "D" Station air compressor and became operable at 1759 hours. The remaining "B" Station Air compressor also tripped at 1731 hours on thermal overload due to inadequate Service Water cooling flow and was subsequently restarted at 1736 hours. The "C" and "D" station Air compressors were unavailable due to the LNP. The five (5) minute interval in which all Station Air compressors were out of service resulted in a 15 psig. Instrument Air header pressure drop. In response to the "B" Station Air Compressor Trip, Operations personnel entered procedure ON 3146, "Low Instrument/Scram Air Header Pressure", and initiated immediate efforts to restart the "B" Station Air Compressor. No air supplied equipment malfunctions were experienced during this interval. The reduced Service Water flow to the Station Air compressors and other plant equipment is being reported separately as Licensee Event Report (LER) 91-12.

At 1925 hours on 04/23/91, 115KV Breaker K186 was manually closed which restored power to the Startup transformers via the Keene (K186) line. 4 KV bus breakers 13 and 23 were subsequently closed to reenergize Buses 1 and 2 which power the normal station loads. Because of the fact that testing was continuing in the Switchyard with only one breaker closed, the decision was made to leave the emergency diesels connected to 4KV buses 3 and 4. This would ensure that power to 4KV buses 3 and 4 would not be interrupted if another LNP occurred.

At 1950 hours on 04/24/91, based on normal off-site power having been restored and Torus water volume having been reduced below 70,000 cubic ft., the Unusual Event was terminated. At 0207 hours on 04/25/91, Shutdown Cooling using the "D" RHR pump on the "B" loop was initiated. The reactor reached cold shutdown at 0357 hours. The reactor was returned to critical at 0300 hours on 04/30/91.

Investigations into the cause of the event, along with troubleshooting, testing, and repair efforts were initiated immediately after the start of the event. A Switchyard response team was formed with specific directives to:

- recover off-site power
- stabilize the switchyard
- gather technical information related to the event
- begin root cause analysis research

DESCRIPTION OF EVENT (cont.)

The recovery of off-site power began with the attempt to restore 115KV power from the Switchyard via 115KV Breaker K186 and the Startup transformers. This was determined to be the easiest path in obtaining an off-site power source due to the need to close only one breaker. However, the K1 Breaker BFI signal remained locked in due to a failed zener diode on the associated trip card and prevented the closure of K186. At 1925 hours, the BFI signal from the K1 to the K186 Breaker was blocked allowing reclosure of K186 and subsequent restoration of power to 4KV buses 1 and 2. The K1 BFI trip card was subsequently replaced with an identical card from a spare breaker. The 4 hour effort to close the K186 breaker was a direct result of the length of time required for New England Power Service Co. (NEPSCO) relay technicians to travel to Vermont Yankee from Providence, Rhode Island.

After 115 KV power was established through the Keene K186 line, efforts to close Breaker K1 continued in order to establish a more reliable source of 115KV power through the Auto Transformer. However, due to communication problems between VY and the New England Switching Authority (REMVEC) concerning priorities over breaker testing, a three hour delay occurred before 115KV power was made available through the Auto Transformer. While Vermont Yankee was attempting to close the K1 breaker, REMVEC was pursuing efforts to establish connections between the ring bus and the Northfield line by reclosing the 81-1T breaker.

In a parallel effort, at 1900 hours, Operation orders were given to complete backfeeding of the plant from the 345 yard through the Main Transformer. The effort to backfeed was possible due to the availability of the Coolidge and Scobie lines. The Northfield line was unavailable due to the 81-1T BFI signal. Again, the backfeed effort was hampered by communication problems with REMVEC, personnel delays, and equipment malfunctions. Backfeeding was completed at 0410 hours on 04/24/91. Vermont Yankee Technical Specification requirements for Off-Site Power were met during the Backfeeding effort by the availability of one off-site transmission line (Keene K186 line in service) and a delayed access power source (Vernon Hydro Station).

In conjunction with the above efforts, Maintenance department personnel with the help of technicians supplied by NEPSCO and the battery charger vendor, performed preventative and corrective maintenance on the four battery chargers related to DC Bus 4A and 5A. Significant repairs and testing were performed on the affected units. Additional testing and repairs were initiated to the Stuck Breaker Failure Unit (SBFU) Logic trip cards for the 81-1T, 381 and K1 breakers. The cards for 381 and K1 breakers were found to have failed zener diodes. The 81-1T (SBFU) relay was found to be functioning properly.

DESCRIPTION OF EVENT (cont.)

Discussions with the manufacturer indicated that the zener diodes are no longer employed on newer revision trip cards and have recommended the removal of the zener diodes based on their vulnerability to voltage transients. Based on this recommendation, the Maintenance Dept. has removed the zener diodes from these units in accordance with written direction from the vendor.

After response team efforts were completed, a Root Cause/Corrective Action Report (CAR) was drafted on the event from a Switchyard perspective. In the draft report, the following conclusions were reached:

- The voltage transient on the DC 4A bus occurred when battery charger 4A-5A was disconnected from the DC-5A bus which rendered bus DC 4A susceptible to voltage spikes due to the absence of a battery bank.

- The specific cause of the zener diode failures which resulted in the 81-1T and K1 breaker (BFI) signals is attributed to the voltage transient which occurred on Bus DC 4A.

- A portion of the additional problems found with DC Bus 4A and 5A battery chargers which ranged from shorted diodes/SCRs and blown surge suppressor fuses, were concluded to be pre-existing and were responsible for the voltage transient.

CAUSE OF EVENT

The Root Cause of this event is the failure of the repair department personnel to recognize the consequences of operating a DC bus without a connected battery bank. The Maintenance Guideline, an internal Maintenance Department document prepared by the department Electrical Engineering staff, was inadequate in that it did not take into consideration all battery charger failure modes when floating a DC bus without a battery bank. The consequences of losing battery charger power while the bus is energized without a battery connected were considered during the revision of the Guideline, but not the potential of the battery chargers to fail high or induce a high voltage spike on the bus, both which have the potential to damage electronic circuitry.

The previous revision of the Guideline called for the two DC buses (4A & 5A) to be cross-connected and fed jointly by the 4A/5A battery charger during the maintenance on the batteries. Following cross-connection, the Guideline required opening of the battery breakers. This evolution was successfully accomplished and the required work on the

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TEXT (If more space is required, use additional NRC Form 366A) (17)

CAUSE OF EVENT (cont.)

batteries was completed without incident. Recovery of the battery required the closure of the battery output breaker first, essentially paralleling the two battery banks until the 4A/5A charger output breaker was opened. In June 1990, the Guideline was revised due to Operations Department concern with paralleling batteries. The new revision required that the cross connection between bus 4A and 5A provided by battery charger 4A/5A be opened prior to the reclosure of the bus 4A battey breaker. This configuration rendered bus 4A without a battery and susceptible to voltage excursions from either the 4A or 4A/5A battery chargers.

CONTRIBUTING CAUSES

1. 345KV and 115KV breaker failure relays were susceptible to false initiation due to control voltage transients.

2. The switchyard battery chargers were in a degraded mode such that they created DC bus control voltage disturbance when the chargers were disconnected from associated batteries.

3. Lack of Switchyard battery charger and overall Switchyard preventative maintenance.

ANALYSIS OF EVENT

The events had minimal adverse safety implications.

1. The plant responded to the reactor trip and LNP as designed. The Emergency Diesel Generators operated as designed and supplied power to Emergency plant buses until off-site power was restored.

2. The Reactor Protective System operated as designed and scrammed the reactor on Generator Load Reject resulting from the 345KV Breaker Failure Signal

3. An evaluation was performed by the Operations Department relevant to the loss of both "A" and "B" Station Air compressors. The analysis concluded that the 5 minute interval in which the "B" Station Air compressor was out of service which resulted in a 15 psig. drop in the station air supply system did not significantly challenge any plant equipment.

4. All other safety systems responded as expected.

CORRECTIVE ACTIONS

SHORT TERM CORRECTIVE ACTIONS

1. Immediate corrective actions included recovering from the reactor scram, restoration of off-site power, and Switchyard and reactor stabilization utilizing appropriate plant procedures.

2. The current revision of the Maintenance Dept. Guideline has been cancelled and the previous revision reinstated with an additional requirement that a review be performed prior to its use for dealing with any evolution requiring switchyard battery removal.

3. Review all other plant guidelines and Procedures pertaining to battery switching operations.

LONG TERM CORRECTIVE ACTIONS

Long Term Corrective Actions are presently being addressed per our Root Cause/Corrective Action process. The Corrective Action Report is presently being finalized. In accordance with prior commitments made to the NRC at the AIT exit meeting held in King of Prussia on 05/14/91, a letter detailing plant Corrective Actions to be initiated in response to the event and NRC concerns will be forwarded to the NRC by 07/15/91. Based on information presented in the finalized Corrective Action Report, a supplement to this report will be forwarded to the Commission.

ADDITIONAL INFORMATION

There have been no similar events of this type reported to the commission in the past five years.

ATTACHMENTS

Sketches: a. Switchyard Distribution

b. Switchyard DC Bus System

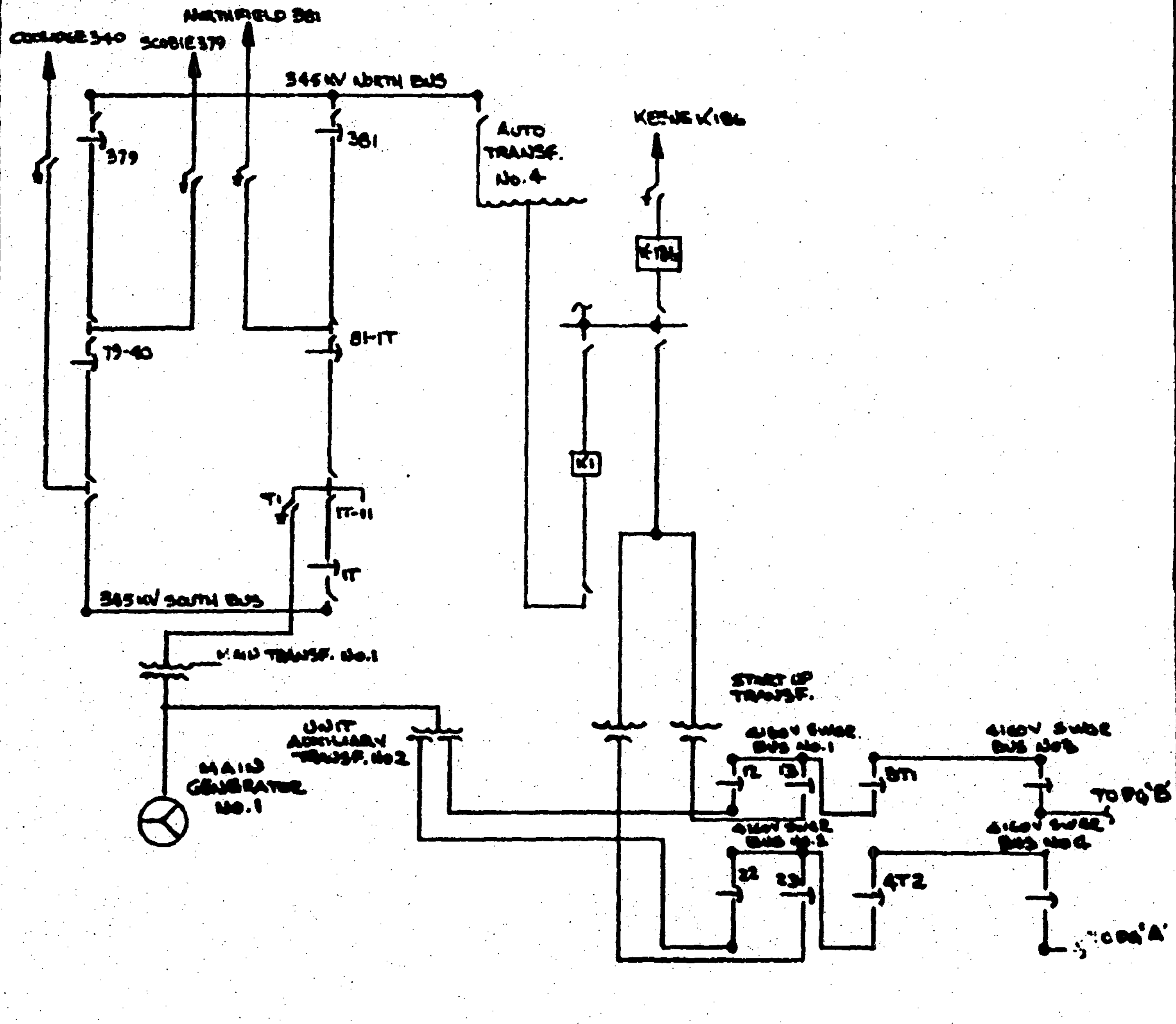
NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION
(6-89)

APPROVED OMS NO.3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

UTILITY NAME (1)	DOCKET NO. (2)	LER NUMBER (6) YEAR	-	SEQ. #	-	REV#	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1	-	0 0 9	-		OF

TEXT (If more space is required, use additional NRC Form 366A) (17)



SWITCHYARD DISTRIBUTION

NRC Form 366A (6-89)

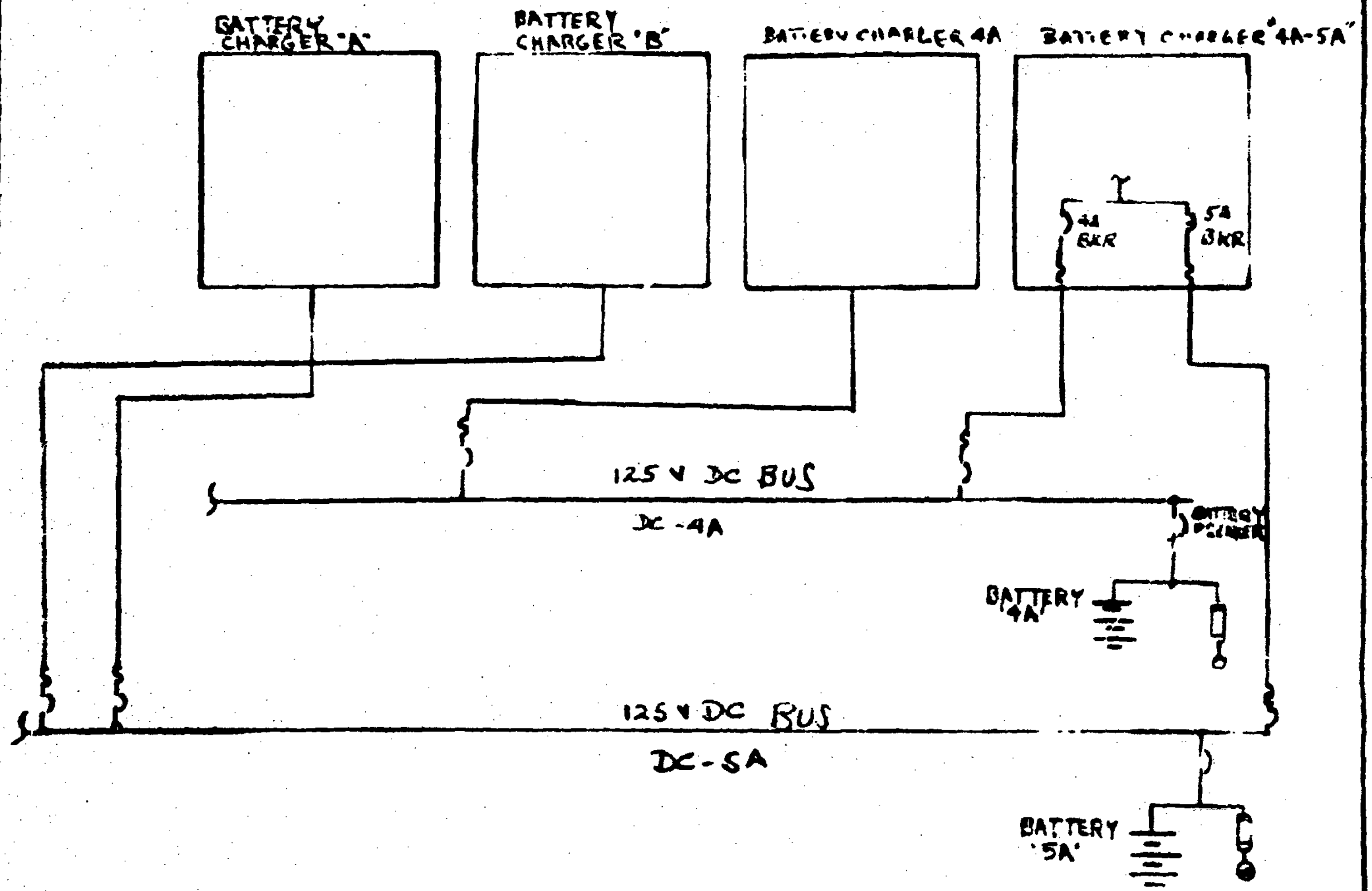
NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION
(6-89)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

UTILITY NAME (1)	DOCKET NO. (2)	LER NUMBER (6) YEAR	SEQ. #	REV#	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1 -	0 0 9 -		OF

TEXT (If more space is required, use additional NRC Form 366A) (17)



SWITCHYARD DC BUS SYSTEM

19

VERMONT YANKEE NUCLEAR POWER CORPORATION

P.O. Box 157, Governor Hunt Road
Vernon, Vermont 05354-0157
(802) 257-7711

July 11, 1991
VYV # 91-148

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

REFERENCE: Operating License DPR-28
Docket No. 50-271
Reportable Occurrence No. LER 91-14

Dear Sirs:

As defined by 10 CFR 50.73, we are reporting the attached Reportable Occurrence as LER 91-14.

Very truly yours,

VERMONT YANKEE NUCLEAR POWER CORPORATION

Donald A. Reid
Plant Manager

cc: Regional Administrator
USNRC
Region I
475 Allendale Road
King of Prussia, PA 19406

IE22
1/1

NRC Form 366 U.S. NUCLEAR REGULATORY COMMISSION (6-89)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NO. (2)	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	0 1 OF 0 4

TITLE (4) Reactor Scram Due to Loss of 345KV Switchyard Caused by Defective Off-Site Carrier Equipment

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ #	REV#	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NO.(S)
0 6	1 5	9 1	9 1	0 1 4	0 0	0 7	1 5	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10 CFR §: CHECK ONE OR MORE (11)

[ ]	20.402(b)	[ ]	20.405(c)	[X]	50.73(a)(2)(iv)	[ ]	73.71(b)
[ ]	20.405(a)(1)(i)	[ ]	50.36(c)(1)	[ ]	50.73(a)(2)(v)	[ ]	73.71(c)
[ ]	20.405(a)(1)(ii)	[ ]	50.36(c)(2)	[ ]	50.73(a)(2)(vii)	[ ]	OTHER:
[ ]	20.405(a)(1)(iii)	[ ]	50.73(a)(2)(i)	[ ]	50.73(a)(2)(viii)(A)		
[ ]	20.405(a)(1)(iv)	[ ]	50.73(a)(2)(ii)	[ ]	50.73(a)(2)(viii)(B)		
[ ]	20.405(a)(1)(v)	[ ]	50.73(a)(2)(iii)	[ ]	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NO. AREA CODE	
DONALD A. REID, PLANT MANAGER	8 0 2	2 5 7 - 7 7 1 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS	CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS
X	F K	T [illegible] R C	[illegible]	N					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MO	DAY	YR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approx. fifteen single-space typewritten lines) (16)

On 06/15/91 at 2224 hours, during normal operation with Reactor power at 100%, a Reactor Scram occurred due to a Turbine Control Valve Fast Closure on Generator Load Reject resulting from a loss of the 345KV North Switchyard Bus. The event was initiated during a thunderstorm in which a lightning strike occurred on the "B" phase of the 381 transmission line between Vermont Yankee and Northfield. The fault resulted in the opening of all 345KV Air Trip Breakers (ATBs).

During the event, a subsequent Reactor Scram and corresponding Primary Containment Isolation Signals (PCIS)(*JM) Groups 2 and 3 were received due to Low Reactor Water level. The Reactor was stabilized in Hot Standby using the Main Condenser, Condensate, and Feedwater systems. At 2100 hours on 06/16/91, after Reactor depressurization was completed, Shutdown Cooling using the "D" RHR pump on the "B" loop was initiated. The reactor reached Cold Shutdown at 0500 hours on 06/17/91. The reactor was returned to critical at 1413 hours on 06/20/91.

The Root Cause of this event is a defective (shorted) transistor in offsite (Scobie Pond) Protective Relaying System Carrier equipment. The need to perform additional testing of Carrier systems is being evaluated.

*Energy Information Identification System (EIIS) Component Identifier

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89)

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NO (2)	LER NUMBER (6) YEAR	SEQ #	REV #	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1	- 0 1 4 -	0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A) (17)

DESCRIPTION OF EVENT

On 06/15/91 at 2224:22 hours, during normal operation with Reactor power at 100%, a Reactor scram occurred as a result of Turbine Control Valve Fast Closure on Generator Load Reject due to a loss of the 345KV North Switchyard Bus. The event was initiated during a thunderstorm in which a lightning strike occurred on the "B" phase of the 381 transmission line between Vermont Yankee and Northfield, Ma. The fault resulted in the opening of the 81-1T and 381 Air Trip Breakers (ATBs). An unanticipated trip of the 379 Scobie line on Carrier Overreach also occured coincident with the fault resulting in trips of the 379 and 79-40 ATBs. The cumulative effect of the breaker openings left only the Coolidge (340) Line connected to Vermont Yankee. This line subsequently tripped on overload, opening the 1T ATB. With all 345KV ATBs open, all load paths for Vermont Yankee's output were shed which resulted in a Generator Load Reject and subsequent plant scram.

Following the Generator Load Reject and Turbine Control Valve Fast Closure, plant buses remained connected to the Main Generator via the Aux Transformer for approximately 30 seconds at which point the Turbine tripped from a "Lo" Scram Air Header Pressure Time Delayed Signal. During the first 10 seconds of this interval, plant buses experienced voltage oscillations while the Main Generator voltage output attempted to regulate during the transition from 100% to approximately 5% load. The voltage oscillations experienced resulted in the following major system responses:

- Primary Containment Isolation System (PCIS)(*JM) Groups 1A, 2A, 3A, 5A and 5B were received due to low 120VAC Instrument bus voltage resulting in the closure of Group 5 Isolation valves as required.

- "A" and "B" Station Air Compressors tripped due to low 120VAC Instrument bus voltage. Both air compressors were restarted at 2233 hours.

- Reactor Recirculation Units (RRUs) 2 and 4 Tripped due to dropout of a 120VAC Drywell Cooling and Control Room Air Conditioning Blocking relay from low voltage. Both RRUs were restarted at 2233 hours.

- "B" and "C" Reactor Feedwater Pumps Tripped on Low Suction Pressure resulting from transients in the Condensate System which were caused by the undervoltage conditions. Feed flow was restored within 10 seconds.

- "A" and "B" Recirc Pump Breakers opened due to Low Lube Oil Pressure. The loss of Lube Oil was a result of blown control circuit fuses.

- "A" and "B" Advanced Off Gas (AOG) Recombiners tripped due to low 120VAC Instrument bus voltage. This resulted in the blowout of a Steam Jet Air Ejector (SJAE) Rupture Disc.

In addition to the (low voltage) received PCIS signals, a decreasing 127 inch "LO" Reactor Water level was experienced 7 seconds into the event, at 2224:29 hours, generating a Reactor Scram and remaining PCIS Group 2B and 3B isolation signals resulting in the required Group 2 and 3 isolations. The water level reached a low of 122 inches and is attributed to void collapse from the initial Scram.

*Energy Information Identification System (EIIS) Component Identifier

TEXT (If more space is required, use additional NRC Form 366A) (17)

DESCRIPTION OF EVENT (cont'd)

Approximately 10 seconds into the event, at 2224:32 hours, the 381 ATB reclosed which reenergized the Auto Transformer. The 379 ATB reclosed 12 seconds later at 2224:44 hours. Coincident with the turbine trip at 2224:50 hours, a Generator Lockout was initiated which resulted in Fast Transfer of plant buses to the Startup Transformers. With reliable 115KV power available from the Auto Transformer, 4KV and 480V Bus voltages remained stable from this point on.

In response to the Scram, Operations personnel entered Emergency Operating Procedure OE-3100 "Scram Procedure" which governs reactor operation in a post-scram environment. Operators noted during the Scrams that approximately 25% of the Control Rods lacked "Full In" indication (the associated rod display was blank). Reactor power was verified to be less than 2%, by Average Power Range Monitor (APRM) downscale indication. This condition prompted the entry into Emergency Operating Procedure OE-3101 "Reactor Pressure Vessel (RPV) Control Procedure" in which a Manual Scram was initiated at 2226 hours and subsequently reset at 2228 hours. Upon resetting of the Scram, all rods indicated "00" and OE-3101 was exited. The loss of indication for a portion of the Control Rods is attributed to a known phenomena called rod overtravel in which a loss of position indication can occur if a control rod inserts slightly past the full in position resulting in a misalignment of the corresponding position indication switches.

During the event, Reactor pressure and level were maintained using the Main Condenser, Condensate, and Feedwater systems. At 2100 hours on 06/16/91, Shutdown Cooling was initiated using the "D" RHR pump on the "B" loop. The reactor reached Cold Shutdown at 0500 hours on 06/17/91. The reactor was returned to critical at 1413 hours on 06/20/91.

CAUSE OF EVENT

The Root Cause of this event is a defective (shorted) transistor in offsite (Scobie Pond) Protective Relaying System Carrier equipment. The lightning strike which occurred on the "B" phase of the 381 Transmission line between VY and Northfield, Ma. would normally have only resulted in an isolation of the 381 line. However, the defective component in the Scobie Pond Carrier equipment caused a subsequent loss of the 379 line. This routed the full Generator output through the 340 (Coolidge) line. The Coolidge line cannot handle full generator output and tripped out on overload which resulted in a loss of the 345KV yard and caused the Reactor to Scram on Generator Load Reject.

After the plant Scram, an extensive testing and troublshooting effort was performed by Vermont Yankee and New England Power Service Co. (NEPSCO) to determine the cause of the Scobie Line Carrier trip. It was found that the the equipment on the VY end operated as designed and sent a Carrier block signal to Scobie to prevent tripping. Although the signal was received at Scobie Pond, the trip signal was not blocked. A failed transistor in the Carrier equipment logic section prevented the blocking signal from reaching the tripping logic. Since the tripping logic did not see a blocking signal it caused the Scobie line to trip at Scobie Pond and Vermont Yankee.

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

FACILITY NAME (1)	DOCKET NO (2)	LER NUMBER (6) YEAR	SEQ #	REV #	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1	- 0 1 4	- 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A) (17)

CONTRIBUTING CAUSES

1. Lightning strike on the B phase of the Northfield line was the contributing cause to the event.

ANALYSIS OF EVENT

The events had minimal adverse safety implications.

1. The Reactor Protective System operated as designed and scrammed the reactor on Generator Load Reject resulting from the loss of 345KV power.
2. Fast transfer to an off-site source occurred as designed upon receipt of a Generator Lockout.
3. All other safety systems responded as expected.

CORRECTIVE ACTIONS

SHORT TERM CORRECTIVE ACTIONS

Immediate corrective actions included recovering from the reactor scrams, troubleshooting and repair of the Scobie Pond equipment, and reactor stabilization utilizing appropriate plant procedures.

LONG TERM CORRECTIVE ACTIONS

VY Maintenance Department and VELCO Switchyard Engineers will evaluate testing requirements for Switchyard Carrier systems.

The above Long Term Corrective Action will be completed by 11/01/91.

ADDITIONAL INFORMATION

There have been no similar events of this type reported to the commission in the past five years.

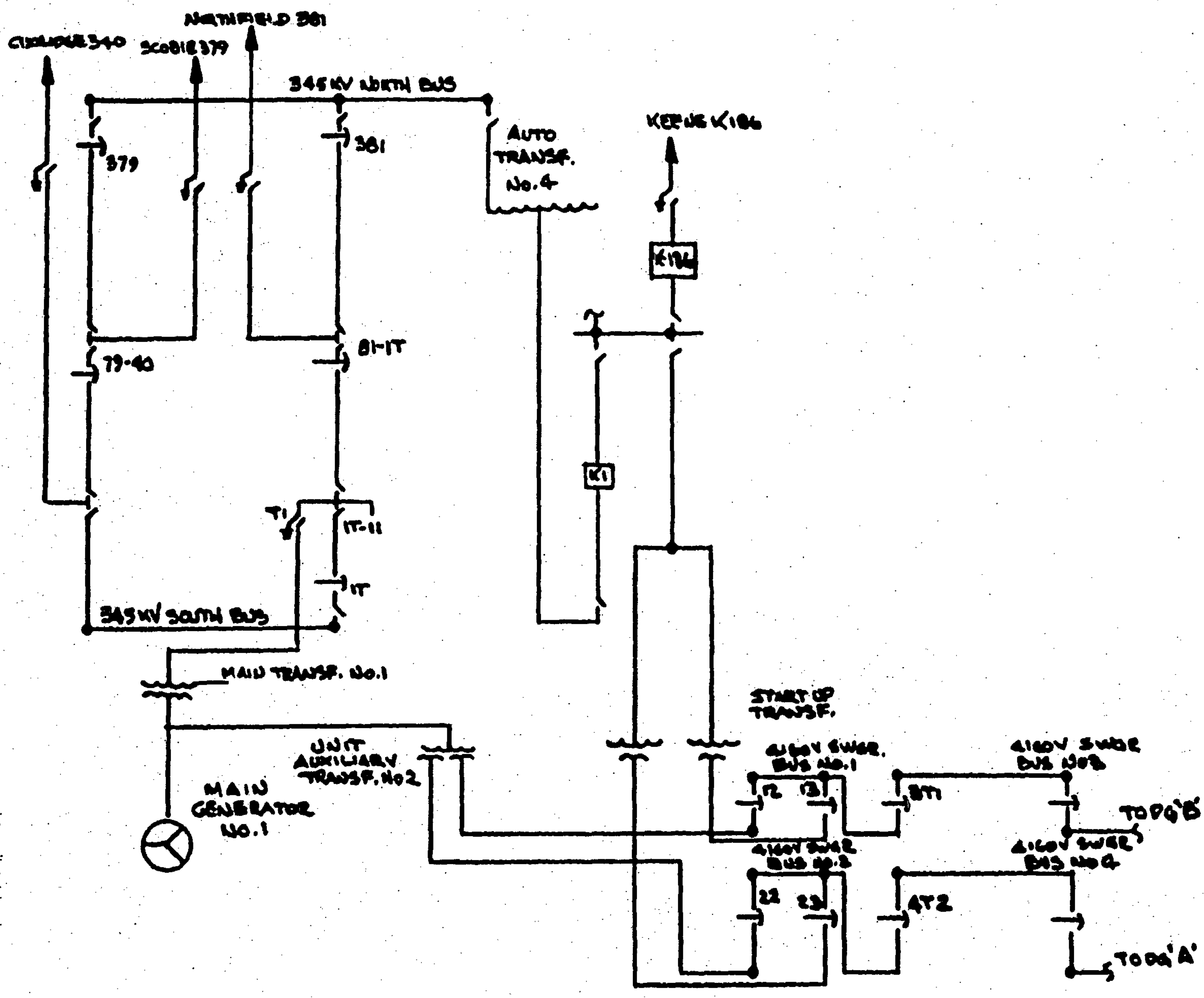
ATTACHMENTS

SKETCH: Switchyard Distribution

NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NO (2)	LER NUMBER (6) YEAR	-	SEQ #	-	REV #	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1	-	0 1 4	-	0 0	OF

TEXT (If more space is required, use additional NRC Form 366A) (17)



SWITCHYARD DISTRIBUTION

20

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
Vermont Yankee
P.O. Box 0500
185 Old Ferry Road
Brattleboro, VT 05302-0500
Tel 802 257 5271

June 14, 2005
BVY 05-064

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: **Vermont Yankee Nuclear Power Station**
License No. DPR-28 (Docket No. 50-271)
Reportable Occurrence No. LER 2004-003-01

As defined by 10 CFR 50.73(a)(2)(iv)(A), we are submitting the attached revision for a Reportable Occurrence that occurred on June 18, 2004 as LER 2004-003-01 to report a change to the root cause of the event based upon the results of laboratory analysis.

Sincerely,

Entergy Nuclear Operations, Inc.
Vermont Yankee

William F. Maguire
General Manager, Plant Operations

cc: USNRC Region I Administrator
USNRC Resident Inspector - VYNPS
USNRC Project Manager - VYNPS
Vermont Department of Public Service

IE22

NRC FORM 366 (6-2004) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: NO. 3150-0104 EXPIRES: 06/30/2007
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records and FOIA/Privacy Service Branch (T-5 F52), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
VERMONT YANKEE NUCLEAR POWER STATION (VY)	05000 271	1 OF 5

4. TITLE
Automatic Reactor Scram due to a Main Generator Trip as a result of an Iso-Phase Bus Duct Two-Phase Electrical Fault

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME: N/A	DOCKET NUMBER: 05000
06	18	2004	2004	- 003 -	01	06	14	2005	FACILITY NAME: N/A	DOCKET NUMBER: 05000

9. OPERATING MODE: N

10. POWER LEVEL: 100

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☑ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER (Include Area Code)
William F. Maguire, General Manager Plant Operations	(802) 257-7711

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
E	EL	FCON	P295	Yes	E	EL	IPBU	P295	Yes
E	EL	BDUC	P295	Yes	E	EL	LAR	G066	Yes

14. SUPPLEMENTAL REPORT EXPECTED	15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
○ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)* ◉ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On 06/18/04 at 0640, with the plant at full power, a turbine load reject scram occurred due to a two phase electrical fault to ground on the 22 kV iso-phase bus. All safety systems responded as designed and the reactor was shutdown without incident. Off-site power transmission lines and station emergency power sources were available throughout the event. Arcing and heat generated during the fault damaged an area around the iso-phase bus ducts and Main Transformer low voltage bushings. The electrical faults disrupted an oil line flange between the Main Transformer oil conservator (expansion tank) and the "C" phase low voltage bushing box, and the leaking oil ignited. Fire suppression systems activated automatically. An Unusual Event was declared at 0650 for a fire lasting greater than 10 minutes. The VY fire brigade and local community fire departments declared the fire under control at 0717. At 1245, the Unusual Event was terminated. The electrical grounds that initiated the event were caused by loose material in the "B" iso-phase bus duct as a result of the failure of a flexible connector. The grounds raised the voltage on the "A" and "C" iso-phase busses contributing to the failure of the "A" phase surge arrester. The root causes of the event were determined to be the result of a flexible connector fabrication deficiency and preventative maintenance not being performed on the surge arresters located in the Main Generator Potential Transformer (PT) Cabinet. There was no release of radioactivity, breach of secondary containment or personnel injury during this event.

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

DESCRIPTION:

On 06/18/04 at 0640, with the plant operating at full power, a two-phase electrical fault-to-ground occurred on the 22kV System (EIIS=IPBU, BDUC). The "B" phase faulted to ground in the low voltage bushing box on top of the Main Transformer (EIIS=XFMR), and the "A" phase faulted to ground in the surge arrester cubicle of the Main Generator Potential Transformer (PT) Cabinet through the "A" phase surge arrester (EIIS=LAR).

Within less than one cycle (11 milliseconds) of the initial electrical fault, the Main Generator protective relaying sensed the condition and isolated the generator from the grid within the following 5 cycles (80 milliseconds). A generator load rejection reactor scram then occurred. Approximately 400 milliseconds following the initial electrical faults to ground from "A" and "B" phases, arcing and ionization in the "B" phase low voltage bushing box carried over to the "C" phase low voltage bushing box on top of the Main Transformer. The electrical faults disrupted a flange in the oil piping between the Main Transformer oil conservator (expansion tank) and the "C" phase low voltage bushing box. The arcing or heat from the fault ignited the oil, resulting in a fire. Fire suppression systems activated automatically as expected.

The plant response following the scram was as expected, with the exception that both Recirculation pumps tripped and other AC voltage effects were observed as a result of the voltage transient associated with the high fault current. All safety systems functioned as designed and the reactor was shutdown without incident. There was no release of radioactivity and no personnel injuries.

The VY fire brigade was dispatched at 0641. An Unusual Event was declared at 0650 due to "Any unplanned on-site or in-plant fire not extinguished within 10 minutes". The VY fire brigade initiated fire hose spray from a nearby hydrant and quenched the fire. Local fire departments began arriving at 0705. The fire was declared under control at approximately 0717 and re-flash watches were established. Off-site power transmission lines and station emergency power sources were available at all times throughout the event.

The States of Vermont, New Hampshire and Massachusetts were provided with initial notification of the event at 0721. The NRC Operations Center was notified of the event at 0748, recorded as NRC Event Number 40827. In addition to the declaration of the emergency classification, a 4-Hour NRC Non-Emergency Notification was completed due to an RPS actuation with the reactor critical, pursuant to 10CFR50.72(b)(2)(iv)(B). At 1245, the Unusual Event was terminated.

The iso-phase bus flexible connector (EIIS=FCON) that failed (expansion joints) was part of the original bus supplied and designed by H. K. Porter, Drawing Numbers G-191144 & G-191146. All flexible connectors were replaced with an upgraded design supplied by Delta-Unibus. The surge arresters were GE Alugard Station Arrestors, Model Number 9L11LAB, installed as original plant equipment. All of the surge arresters were replaced.

CAUSES:

The root causes of the event were determined to be the result of a flexible connector fabrication deficiency and preventative maintenance not being performed on the surge arresters located in the Generator Potential Transformer (PT) Cabinet.

The electrical grounds that initiated the event were caused by loose material in the "B" iso-phase bus duct as a result of the failed flexible connector that allows the iso-phase bus to thermally expand and contract. The grounds raised the voltage on the "A" and "C" iso-phase busses, contributing to the failure of the "A" phase surge arrester.

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
VERMONT YANKEE NUCLEAR POWER STATION (VY)	05000 271	2004	– 003	– 01	3 OF 5

17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

Although the iso-phase bus is subjected to preventative maintenance cleaning and Doble Testing each refueling outage, the cleaning and inspection is limited to the stand-off insulators. Additional inspections to evaluate the condition of the bus (including its flexible connectors) would have detected the degraded flexible connectors.

A detailed equipment failure evaluation was conducted on the flexible connectors associated with the Main Generator 22 kV Electrical System. The cause of the "B" phase flexible connector failure was that weld porosity and excessive weld grinding (reinforcement removal) during original fabrication weakened the laminate weld.

During approximately 32 years of plant operation, differential thermal expansion and contraction caused thermally induced stress at the flexible connector attachment welds. These thermally induced stresses caused the propagation of fatigue cracks at the attachment welds. The fatigue cracks grew and, combined with voids in the weld metal and lack of edge welds, resulted in over stressing the remaining weld metal that failed due to tensile and shear over load ultimately leading to the failure and separation of the outer laminate from the bus. The end closest to the generator on the "B" phase flexible connector failed first allowing the outer laminate to be lifted into the cooling air flow, thereby placing additional stresses on the undersized weld ligaments at the transformer end.

There was no sign of cracking at any other flexible connector weld, indicating that the increased air flow/velocity in the bus duct did not result in flow induced vibration of the outer laminates and contribute to the failure. The increased air flow within the bus duct following the refueling outage modifications may have accelerated the failure timetable for the laminate; however, the failure would have occurred at some time in the near future at the original flow rates.

The need for inspecting the flexible connectors was identified during a recent review of industry operating experience (OE). This OE is being included as recommended preventative maintenance for future outages; however, it was not included in the preventative maintenance inspection performed during RFO-24.

The "A" surge arrester failure was the result of the combination of a ground occurring on the "B" iso-phase bus that caused an increase in voltage on the "A" and "C" iso-phase busses and not performing preventative maintenance necessary to monitor age related degradation of the "A" surge arrester. Industry experience has revealed that surge arresters degrade over time due to a combination of age, service environment and service conditions. Periodic inspection/testing could have detected degradation and allowed replacement prior to failure.

Three contributing causes were identified by the investigation: failure to effectively use industry OE to prevent similar events from occurring at VY, inadequate preventive maintenance of the generator iso-phase bus, and inadequate failure modes and effects evaluation. Specifically, it was noted that; the actions taken by VY in response to recommendations provided within the INPO Significant Operating Experience Report (SOER) 90-01 for "Ground Faults on AC Electrical Distribution" were inadequate. In addition to the SOER, guidance provided within EPRI's "Isolated Phase Bus Maintenance Guide" TR-112784 (1999) for the 22 kV flexible connectors and periodic inspections/testing was not utilized.

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17. NARRATIVE *(If more space is required, use additional copies of NRC Form 366A)*

ASSESSMENT OF SAFETY CONSEQUENCES:

All safety systems and fire suppression systems responded as designed. The reactor was shutdown without incident. Off-site power sources and station emergency power sources were available at all times throughout the event. Emergency response personnel acted promptly to prevent the fire from significantly damaging or breaching the adjacent turbine building. There was no release of radioactivity or personnel injury during this event. Therefore, this event did not significantly increase the risk to the health and safety of the public.

CORRECTIVE ACTIONS:

Immediate:

1. An Unusual Event was declared at 0650.
2. The station fire brigade on scene to combat the fire at 0652. Local fire departments arrived on-site at 0705 to provide assistance. The fire was under control at 0717.
3. Completed the initial notification to the States of Vermont, New Hampshire and Massachusetts at 0721.
4. Notified the NRC Operations Center of the Unusual Event at 0748.
5. Secured all affected site and plant areas for personnel safety and isolated affected equipment as necessary to maintain investigation integrity.
6. Condition Reports were generated for this event and potentially associated issues as appropriate for entry into the Corrective Actions Program.
7. A Root Cause Investigation team was established to assess damage and to secure the area.
8. Initial testing was completed on the main transformer, station auxiliary transformer, and main generator with no indication of damage that would affect the operation of the transformers or generator.
9. A Preliminary Nuclear Network Entry was completed to inform the industry of the initial findings and conditions of the event.

Prior to Plant Start Up:

1. The phase A, B, and C 22 kV surge arresters and capacitors were replaced prior to energizing the 22kV bus.
2. The phase A, B, and C 22 kV flexible connectors were replaced with an upgraded design supplied by Delta-Unibus prior to energizing the 22kV bus.
3. A cleanliness inspection was performed and documented as part of Iso-Phase Bus Duct Modification.
4. Maintenance department personnel inspected the cooler and leads fans for foreign material. Following operation of the fans, an additional inspection of the fans and coolers was performed.
5. Operator Alarm response sheets were revised to enhance operator actions in the event of future ground faults.
6. A preventative maintenance schedule was established for increased sampling of transformer oil for the main, auxiliary, and two startup transformers for four weeks after start-up.
7. The iso-phase bus duct system was monitored after assembly with the fans running to ensure that vibration levels were acceptable.
8. VY discussed this event and associated issues with the Entergy Fleet and industry experts as necessary to gather information pertinent to the root cause investigation and equipment recovery.

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Long Term:

1. The 22kV surge arresters and capacitors have been included in the preventative maintenance program with specifically defined periodic replacement requirements. With this change the cubicles containing these components have been assigned unique Preventative Maintenance Identification numbers and the activities associated with the planned maintenance has been expanded to reflect lessons learned from this event.
2. The 22kV iso-phase bus preventative maintenance program was revised to provide periodic inspection requirements to prevent recurrence of this event. This revision provides direction for extensive iso-phase bus inspection, including the flexible connections.
3. Completed testing of the selected components involved in the event. The root cause analysis report has been revised to reflect the findings from the off-site lab analysis.

ADDITIONAL INFORMATION:

Approximately 350 Condition Reports generated since 06/01/1995 regarding the components and systems involved with this event were reviewed during the root cause investigation. No similar event with a related cause was identified to have occurred at Vermont Yankee during this period.

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
Vermont Yankee
P.O. Box 0500
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Brattleboro, VT 05302-0500
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September 22, 2005
BVY 05-087

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: **Vermont Yankee Nuclear Power Station**
License No. DPR-28 (Docket No. 50-271)
Reportable Occurrence No. LER 2005-001-00

As defined by 10 CFR 50.73(a)(2)(iv)(A), we are reporting the attached Reportable Occurrence that occurred on July 25, 2005 as LER 2005-001-00. No Regulatory Commitments have been generated as a result of this event.

Sincerely,

Entergy Nuclear Operations, Inc.
Vermont Yankee

William F. Maguire
General Manager, Plant Operations

cc: USNRC Region I Administrator
USNRC Resident Inspector - VYNPS
USNRC Project Manager - VYNPS
Vermont Department of Public Service

NRC FORM 366 (6-2004) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: NO. 3150-0104 EXPIRES: 06/30/2007
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records and FOIA/Privacy Service Branch (T-5 F52), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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4. TITLE
Reactor Trip Caused by an Electrical Insulator Failure in the 345 kV Switchyard due to a Manufacturing Defect

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME N/A	DOCKET NUMBER 05000
07	25	2005	2005	- 001 -	00	09	22	2005	FACILITY NAME N/A	DOCKET NUMBER 05000

9. OPERATING MODE: N

10. POWER LEVEL: 100

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☑ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER Specify in Abstract below or in NRC Form 366A
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	

12. LICENSEE CONTACT FOR THIS LER

CONTACT NAME	TELEPHONE NUMBER (Include Area Code)
William F. Maguire, General Manager Plant Operations	(802) 257-7711

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	FK	INS	L085	Y	B	FK	MOD	S318	Y

14. SUPPLEMENTAL REPORT EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
○ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)*	◉ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On July 25, 2005 at 1525, with the reactor at full power, a generator load reject trip and subsequent reactor trip occurred as a result of an electrical transient that originated in the 345 kV Switchyard. The electrical transient was due to a failure of the 345 kV Motor Operated Disconnect (MOD) Switch, T-1, "C" phase that was caused by the failure of an electrical insulator. An off-site laboratory performed an examination of the porcelain insulator revealing that the failure was caused by a manufacturing defect. The appropriate NRC 4-hour notifications were completed at 1735 in accordance with 10 CFR 50.72(b) as NRC Event Number 41868. This event is being reported as an LER pursuant to 10 CFR 50.73(a)(2)(iv)(A) as an event that resulted in the automatic actuation of systems listed within 10 CFR 50.73(a)(2)(iv)(B). Plant equipment and operator response to the event was as expected, and the reactor was shutdown with no complications. No release of radioactivity or personnel injury occurred as a result of this event. Therefore, this event did not increase the risk to the health and safety of the public.

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DESCRIPTION:

On July 25, 2005 at 1525 with the reactor at full power, a generator load reject trip and reactor scram occurred due to an electrical transient that originated in the 345 kV Switchyard. An electrical insulator [EIIS=INS, FK] failed, causing a failure of the "C" phase on the 345 kV Motor Operated Disconnect (MOD) Switch T-1 [EIIS=, MOD,FK] ultimately leading to a reactor scram. The plant was placed in a stable condition and reactor water level was restored to its normal band within 25 seconds of the condition that promulgated the event. Plant equipment and operator response to the event was as expected and the reactor was shutdown with no complications. The appropriate NRC 4 hour notifications were completed at 1735 in accordance with 10CFR50.72(b) as NRC Event Number 41868. This event is being reported as an LER pursuant to 10CFR50.73(a)(2)(iv)(A) as an event that resulted in the automatic actuation of systems listed within 10CFR50.73(a)(2)(iv)(B).

The T-1 MOD is physically located between the 345 kV windings of the Main Transformer and the Main Generator output breakers 1T and 81-1T. The electrical insulator that failed was located on the line side of T-1 MOD, providing support for the "C" phase of T-1 MOD. The insulator that failed was manufactured by Lapp Insulator Company, Model J80104-70 Post Stack Insulator, Drawing 3597-51, R0.

Following the plant trip, interviews were conducted with personnel who observed the 345 kV Switchyard events as they transpired, thereby supporting the following conclusions:

1. Arcing occurred at the "C" phase of the T-1 MOD switch.
2. Part of the T-1 MOD switch fell, resulting in a number of audible sounds.
3. Flashes occurred while the T-1 parts fell.
4. The 345 kV high line between the tower and the 345 kV Switchyard moved up and down after the insulator fell.
5. T-1 MOD opened after the fault occurred.

During the first 14 seconds of the event, the following automatic system responses occurred as designed without operator intervention. Action times are provided in the brackets succeeding each item where appropriate:

1. The "C" Phase 87/TL1 Differential Relay senses the development of a "C" Phase to Ground Fault that is a result of the arcing at the T-1 disconnect caused by the insulator failure.
2. The Generator 86/TL1 Tie Line Lockout Relay actuated due to a trip signal from the associated "C" Phase 87/TL1 Differential Relay. [T=0]
3. Main Generator Breakers 81-1T and 1T open from the 86/TL1 signal, isolating the fault from the 345/115 kV system. [T=30 to 33 milliseconds]
4. 4 kV Bus 1 and 2 High Speed Synch Check Relays 25/1 and 25/2 indicated a loss of synchronism between the Auxiliary and Startup Transformers. As designed, this blocks a Fast Transfer of station loads to the Startup Transformers as necessary to prevent possible equipment damage that could occur due to an out-of-phase transfer. [T=33 milliseconds]
5. Generator Primary Lockout Relay Trip indication received on ERFIS. [41 milliseconds] NOTE: The Lockout Relay to ERFIS is received via an auxiliary relay, therefore the trip actually occurred 10 milliseconds before the indication was received.
6. Turbine Trip is actuated by a Main Generator Lockout Relay. [T=90 milliseconds]
7. Both channels of the Reactor Protection System (RPS) are received for a full Reactor SCRAM - all rods fully inserted. The ERFIS sequence of events log indicates that the Main Generator Load Reject Scram Signal was received just prior to the Turbine Stop valve Closure Signal. [T=136 milliseconds] RPS system actuation is reportable to the NRC as an LER pursuant to 10CFR50.73(a)(2)(iv)(A).
8. "A" and "C" Reactor Feedwater Pumps are automatically tripped by the 4 kV Bus Fast/Residual Transfer Scheme. This occurs as a result of the Startup Transformer Breakers not closing within 0.3 seconds of the opening of the Auxiliary Transformer Breakers. Reactor Feedwater Pump trips are expected on a Residual Bus Transfer. [T=350 milliseconds]

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9. Breakers 13 and 23 close to re-energize Bus 1 and 2 after bus voltage has decayed to 1000 volts. [T=623-705 milliseconds]
10. "A" Service Water Pump Starts. [T=1 second]
11. "B" Standby Gas Treatment System (SBGT) starts as a result of the Residual Bus Transfer. [T=2 seconds]
12. Reactor Water Level Low (127") Scram Signal initiates a Primary Containment Isolation System (PCIS) Group 2,3 and 5 Isolation. [T=5.5 seconds] PCIS actuation is reportable to the NRC as an LER pursuant to 10CFR50.73(a)(2)(iv)(A).
13. "A" SBGT System starts on a Reactor Water Low Level Signal. [T=7 seconds]
14. The 4 kV Supply Breaker to the "B" Recirculation Motor Generator (MG) trips on MG system oil pressure following a six second delay in MG control logic. [T=8 seconds]
15. Reactor Low-Low Water Level (82.5") and PCIS Group 1 Isolation. The following system actions occurred for the Group 1 Isolation; Main Steam Isolation Valves (MSIVs) closed, Reactor Core Isolation Cooling (RCIC) System start and inject signal, High Pressure Coolant Injection (HPCI) system start and inject signal, both Emergency Diesel Generators started (running unloaded), and the "A" Recirculation Pump MG Supply Breaker tripped. [T=14 seconds]

PCIS actuations are reportable to the NRC as an LER pursuant to 10CFR50.73(a)(2)(iv)(A). The NRC was notified of the PCIS actuation 10CFR50.72(b)(3)(iv)(A).

ECCS actuations are reportable to the NRC as an LER pursuant to 10CFR50.73(a)(2)(iv)(A). The NRC was notified of this event per 10CFR50.72(b)(3)(iv)(A) and 10CFR50.72(b)(2)(iv)(A)

The following operator actions were taken to stabilize the plant:

1. Placed the Mode Switch to Shutdown. [T=21 seconds]
2. Started "B" Reactor Feedwater Pump to re-establish normal level control. [T=25 seconds]

Within 25 seconds following the operator actions, all reactor water low level alarms were clear.

At 2248, Operations documented that HPCI, RCIC, SBGT, and both EDGs had been secured and returned to standby status. Operations then commenced cool down of the reactor.

ANALYSIS:

The events detailed in this report did not have adverse safety implications. The 4 kV Bus Fast/Residual Transfer Scheme operated as designed to secure and transfer electrical loads as necessary to prevent damage to equipment. The Reactor Protection System operated as designed and scrammed the reactor after receiving the Generator Load Reject Scram signal. All other safety systems responded as expected.

An off-site laboratory performed an examination of the porcelain insulator revealing that the failure was caused by a manufacturing defect located below the top of the cemented joint obscuring visual inspection. The lab determined that the defect was not detectable by visual inspection or predictive maintenance. The failure was found to be structural and evidence of a dielectric breakdown was not present; therefore, predictive maintenance techniques, such as corona, acoustic and thermography would not have detected the failure.

CAUSE:

A root cause investigation team determined that the MOD failure was caused by the failure of a porcelain electrical insulator as a result of a manufacturing defect. A laboratory examination of the insulator was performed by an off-site lab. The examination revealed a void area in the cement that attached the failed section of the insulator to the metal flanges and a geometric off-set in the placement of the insulator in the flanges. Close examination of the void

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surfaces showed that this void was pre-existing and occurred during the manufacturing of the assembly. These conditions caused a stress riser to occur on the northwest side when wind and other cyclic loads were applied to the insulator. The repeated cyclical loading and unloading produced a stress crack in the porcelain, weakening the insulator and ultimately leading to failure, prior to it's design lifetime of 40 years. The insulator was original plant equipment.

CORRECTIVE ACTIONS:

1. Failed components in the 345 kV Switchyard were tagged out, grounded and replaced.
2. Visual, thermography and corona inspections of the 345 kV and 115 kV Switchyards was performed. No additional anomalies were identified. The inspections included components such as bus work, disconnect switches, insulators, etc.
3. Testing was performed to evaluate any potential impact on the Main Transformer and found acceptable.
4. The 345 kV high line section between the tower and Switchyard was inspected and found acceptable (that included insulators, disconnects, bus work, etc.).
5. Other T-1 MOD, 1T-22 and 1T-11 insulators were inspected for damage, and none was found.
6. Preliminary lab analysis of failed components was performed.
7. The five remaining Lapp Model J80104-70 insulators on the line and load ends of the T-1 disconnect switch are scheduled for further inspection and replacement during the Fall 2005 scheduled outage (RF-25). Laboratory analysis will be performed on the insulators removed.
8. Insulators in the Switchyard that pose a risk to generation or potential for a loss of off-site power will be evaluated for replacement.
9. The preventative maintenance frequency for the 345 kV and 115 kV Disconnect Switches and Vertical Bus Insulators will be revised. VY will also ensure that the visual inspection attributes include the flange to porcelain cemented joints and entails inspecting for voids, cracks and off-center assemblies.

ASSESSMENT OF SAFETY CONSEQUENCES:

The reactor was safely shutdown without complications. No failure of safety related equipment occurred during or as a result of this event. The T-1 MOD disconnect is a non-safety related component and is not relied upon for the safe shutdown of the plant; hence, there was no impact on nuclear safety. Mitigating safety systems and non-safety systems responded as designed. A reactor trip with a Primary Containment Isolation System (PCIS) Group 1 isolation, concurrent with a loss of feed water is an analyzed event. The T-1 MOD is physically located in the 345 kV Switchyard, outside of the Radiological Controlled Area (RCA). There was no increased radiological risk to plant personnel or the general public.

ADDITIONAL INFORMATION

A similar event occurred on 03/13/91 at VY that was reported to the NRC as LER 91-005-00 on 04/12/91, "Reactor Scram due to Mechanical Failure of 345 kV Switchyard Bus caused by Broken High Voltage Insulator Stack". The root cause of the bus failure was attributed to a loose bus connection at the lower insulator stack between the bus and the tower. Off-site lab analysis of the fractured insulator completed during the two months succeeding the event were inconclusive. The remaining intact pieces were subjected to specific gravity and dye penetration testing in addition to visual examination and mechanical testing for strength versus rating. Other than some evidence of sand-glaze separation on the porcelain surface within the cap, it was determined that the insulator had been properly fired and that no porosity was present. No defects were discovered and the insulator was demonstrated as capable of performing within its designed rating.

January 4, 2006

The Honorable Nils J. Diaz
Chairman
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: VERMONT YANKEE EXTENDED POWER UPRATE

Dear Chairman Diaz:

During the 528th meeting of the Advisory Committee on Reactor Safeguards, December 7-9, 2005, we discussed the Vermont Yankee Extended Power Uprate (EPU) Application. As part of this review, our Subcommittee on Power Uprates held a meeting on November 15 -16, 2005 in Brattleboro, Vermont to receive input from the public, the applicant, and the staff. A second Subcommittee meeting was held in Rockville, Maryland on November 29 - 30, 2005. During our review, we had the benefit of discussions with the staff, the public, and Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy), the licensee. We also had the benefit of the documents referenced.

CONCLUSIONS AND RECOMMENDATIONS

1. The Entergy application for the extended power uprate at the Vermont Yankee Nuclear Power Station (VY) should be approved.

2. The change in the licensing basis associated with the requested containment overpressure credit should be approved.

3. Load rejection and main steam isolation valve closure transient tests are not warranted. The planned transient testing program adequately addresses the performance of the modified systems.

4. The times available to perform critical operator actions remain adequate under EPU conditions.

5. The margin added to the safety limit minimum critical power ratio (SLMCPR) is an appropriate interim measure until General Electric (GE) obtains additional data to complete the validation of nuclear analysis methods.

6. The monitoring that will be performed during the ascension to uprate power provides adequate assurance that, if resonant vibrational modes are induced in the steam dryer, they will be identified prior to component failure.

7. An enhanced, focused engineering inspection was performed. An additional expanded inspection is not warranted.

8. The review standard for extended power uprates (RS-001) provides a structured process

for the review of applications for extended power uprates. Its continued use and improvement are encouraged.

BACKGROUND

Vermont Yankee Nuclear Power Station (VY) is a boiling-water reactor of the BWR/4 design with a Mark-1 containment. Entergy has applied for an extended power uprate of approximately 20% from the current maximum authorized power level of 1593 MWt to 1912 MWt. The application is similar to other uprates that have been approved within the last five years at Duane Arnold, Dresden Units 2 and 3, Quad Cities Units 1 and 2, and Brunswick Units 1 and 2. In Constant Pressure Power Uprates (CPPU), except for steam and feedwater flow rates, plant operating conditions are essentially unchanged from the pre-EPU values. The extra power is generated largely by flattening the power distribution across the core, and the fuel design safety limits are met at the proposed extended power uprate conditions.

DISCUSSION

When a large-break design-basis loss-of-coolant accident (LOCA) and anticipated transient without scram (ATWS) were analyzed at VY at the proposed EPU level using current design basis assumptions and methodologies, the available net positive suction head (NPSH) was found to be insufficient to avoid cavitation of the low pressure coolant injection (LPCI) and core spray pumps. The need for increased NPSH occurs because at the higher power level the suppression pool heats up more in both of these scenarios than at the currently licensed power level. In the calculations performed to support VY's existing operating license, containment pressure was assumed to be atmospheric when computing the available NPSH.

In its application, Entergy requests changing its licensing basis methodology to grant credit for containment accident pressure in determining available NPSH for emergency core cooling pumps for these LOCA and ATWS scenarios. Using conservative methods and a containment leak rate consistent with its technical specifications, Entergy has determined a conservative lower bound for the time-dependent pressure in containment that would result from these scenarios under EPU conditions. The incremental pressure credits that are requested for these two scenarios are less than these computed pressures. For the LOCA scenario, the maximum containment pressure credit is 6 psi, and the total time for which some overpressure credit is required is 56 hours. For the ATWS scenario, the corresponding values are 2 psi and 1 hour.

The ACRS has historically opposed a general granting of containment overpressure credit. In determining whether such credit should be granted, one aspect to be considered is whether practical alternatives exist, such as the replacement of pumps with those with less restrictive NPSH requirements. If no practical alternatives are available, important considerations include (1) the length of time for which containment pressure credit is required and (2) the margin between the magnitude of the pressure increment that is being granted and the expected minimum containment pressure. Another consideration is the nature of the containment design and whether it provides a positive indication of integrity, prior to the event, as is the case in subatmospheric and inerted designs.

Because of the plant configuration, extent of modifications required, and worker dose that would be involved, we conclude that there are no practical design modifications that would preclude the need to consider the request for containment overpressure credit. VY has an inerted containment. There is, then, a low likelihood of significant pre-existing containment leakage. For the ATWS scenario, the magnitude of pressure required to show adequate NPSH is small compared to the accident pressure, and the time during which the overpressure credit is required is short. For the LOCA scenario, although the duration for which the containment overpressure credit is required is comparatively long, the overpressure credit requested is smaller than what is conservatively predicted to be available.

Under the EPU conditions at VY, the general design requirements regarding single failures in design-basis accidents do not prevent granting of the overpressure credit for the LOCA scenario of concern. The worst single failure that was identified by the licensee involves loss of one train of heat removal from the suppression pool. Conservative, bounding calculations show that the containment overpressures during this scenario are higher than needed to provide sufficient NPSH. Allowing no credit for containment overpressure is equivalent to assuming an additional failure that causes loss of the overpressure. Thus, for all scenarios involving only a single failure, sufficient NPSH is available to ensure that pump cavitation damage is avoided. To maintain defense-in-depth, however, it has been staff practice to require the assumption that containment overpressure is not available in assessing the potential for pump damage.

In evaluating Entergy's request for containment overpressure credit, the staff included in its decisionmaking process more realistic analyses to determine whether containment overpressure would be needed at the proposed EPU power level to prevent pump cavitation in actual accident scenarios. The staff also considered the results of probabilistic analyses to assess the risk significance of scenarios in which containment overpressure is lost.

Design-basis accidents are typically analyzed using conservative methodologies and input assumptions to ensure safety in spite of uncertainties in input and methodology. An alternative approach is to use realistic analyses with a more complete and explicit consideration of uncertainties. Such a methodology has not yet been fully developed for analysis of the need for containment overpressure credit. The staff and the licensee have instead performed sensitivity analyses to determine the effect of relaxing some of the conservative assumptions. More realistic values were used for a number of input parameters to determine the associated reduction in the predicted temperature of the suppression pool, which is the major parameter in determining whether overpressure credit is necessary. The staff concluded that, on a more realistic but still conservative basis, the temperature of the suppression pool would not become high enough in the LOCA scenario to require a credit for containment overpressure.

Independent risk analyses were performed by the staff and the licensee to determine the potential risk significance of granting credit for containment overpressure. These analyses included the conservative assumption that the emergency core cooling system (ECCS) success criteria would not be met whenever containment overpressure is lost and design-basis analyses would suggest that overpressure credit was needed, although the licensee's sensitivity studies indicated that peak suppression pool temperature would probably not be high enough that containment overpressure credit would be required. The results of the analyses indicate that the overall risk associated with the EPU is small and that the change in risk resulting from allowing the requested containment overpressure credit is also small.

Although we concur with the staff's conclusion to grant credit for containment overpressure, we would have preferred to see the assessment performed and presented in a more coherent manner, with a more complete and rigorous consideration of uncertainties. The staff is developing additional guidance to be used in the consideration of overpressure credit in the future. We look forward to reviewing their proposed approach.

The staff performed an expanded engineering inspection of VY. Such an inspection was requested by the Public Service Board of the State of Vermont. The inspection focused on safety-significant components and operator actions. It was performed under the direction of the NRC Office of Nuclear Reactor Regulation (NRR) and included regional inspectors and contractors who had no recent oversight responsibilities for VY. There were eight findings, but they were of low safety significance. A number of members of the public asked for a more extensive inspection, similar to that performed at the Maine Yankee plant. Based on the results of the inspection that was performed and the performance of VY as determined by the Reactor Oversight Process, such an extensive inspection is not warranted.

Hardware and operational changes are required for the power uprate. In order to achieve the proposed EPU power level, all three feedwater pumps must operate, rather than the two pumps currently required. If one of these pumps fails, the plant will undergo an automatic runback of power so that the two remaining pumps will be sufficient. A new signal has been added to trip a feedwater pump in the event of a condensate pump trip. A concern has been raised about the potential for loss of all feed pumps due to low suction pressure as a result of a condensate pump trip. Consequently, Entergy has agreed to perform a trip of a condensate pump to demonstrate that it will not cause loss of all feedwater. This will also test the integrated response of control systems associated with recirculation flow runback, feedwater level control, and reactor pressure control.

Entergy does not plan to undertake large transient tests, such as a main steam isolation valve closure that would result in a reactor trip. Such tests would not directly address confirmation of the performance of systems changed to support EPU. The ACRS concurs with the staff's assessment that the large transient tests are not warranted.

Only minor changes have been made in the emergency operating procedures to accommodate EPU modifications. One of the impacts of the power uprate is a reduction in available response time for operator actions. The operators respond in essentially the same manner as for the current operating conditions but, in some cases, have less time to take an action. A systematic assessment has been made by Entergy of the maximum time available for critical operator actions. The VY simulator has been modified to represent the EPU condition and operators have been trained for EPU conditions. The simulator exercises have demonstrated the ability of the operators to respond correctly within the required time period.

The reactor operating domain is defined so that: (1) the core will not be operated in an unstable regime, (2) the minimum critical power ratio is low enough to prevent dryout of the fuel pins, and (3) the linear heat generation rate is low enough to assure the integrity of fuel cladding during steady and transient conditions. The boundaries of this operating domain are based on neutronic and thermal-hydraulic calculations performed by GE. The computer codes that are used in these analyses have been reviewed and approved by the staff.

In reviewing the application of these methods to EPU uprates, the staff determined that the operation of the fuel extends into a region where the expected void fraction within the fuel bundle is greater than that for which the codes have been validated. To demonstrate the ability of the code to predict isotopic concentrations in this regime, GE has committed to performing gamma scans on the fuel design that is being used in the power uprate. In the interim, Entergy has undertaken an "Alternative Approach" in which it has performed an uncertainty analysis for the model predictions and, as a result, has added an additional margin of 0.02 to the SLMCPR. We concur with the staff's assessment that the addition of such a margin is an appropriate interim measure. The review of the adequacy of the GE computer codes is a generic activity that is being undertaken by the staff. We will have an opportunity to review the staff's assessment of these codes in more detail when we consider the MELLLA+ topical report in 2006.

Higher steam and feedwater flow rates at EPU conditions may lead to an increase in flow accelerated corrosion for some components. The evidence indicates that current flow accelerated corrosion rates at VY are low. Many of the components that would most likely be affected use chromium- molybdenum alloy materials that are resistant to flow accelerated corrosion, and Entergy has committed to an inspection program that will provide reasonable assurance that degradation will be detected prior to reaching an unsafe condition.

Increased flow rates also have the potential to induce vibrations that could lead to failure of components. Because of the previous experience at Quad Cities, the steam dryer has been the primary focus of attention. A number of cracks have been found in inspections of the VY steam dryer. Two cracks found near the lifting lugs were attributed to the initial fabrication of the steam dryer. These cracks have been ground out and repaired. The other cracks that have been found appear to be superficial and were deemed to be the result of intergranular stress corrosion, not flow-induced vibration. Stiffeners have been added to the dryer to provide additional strength and also to raise its natural frequencies.

Entergy has performed hydrodynamic, acoustic and structural resonance analyses to assess the potential for stimulation of a resonant mode of the dryer. These analyses indicate that there is margin between the magnitude of the potential stresses imposed on the steam dryer and the level at which fatigue failure would occur. However, the state of validation of these methods is poor.

To provide further assurance of the integrity of the dryer, additional strain gages have been added to the steam lines at VY. Experiments performed in a scale-model system by GE indicate that acoustic signals initiated in the region of the steam dryer can be correlated with signals measured by strain gages on the steam lines. A similar correlation has been observed at Quad Cities Unit 2 where both the steam dryer and steam lines have been instrumented.

Entergy has developed a program for power ascension involving holds at a number of power levels. The steam line strain gages will be monitored at the various power levels. Any anomalies will lead to a reduction in power until the issue is resolved. Entergy has also committed to inspections of the steam dryers in the next three outages following the uprate. The additional monitoring, the power ascension program, and the inspections provide confidence that, if excessive excitation does occur in the steam dryer, it will be identified before substantial damage is incurred.

Power uprates are not submitted as risk-informed license applications. Nevertheless, licensees have submitted assessments of risk associated with the extended power uprates and the staff includes consideration of this risk information in its decisionmaking process. The purpose of the staff's risk review as stated in RS-001 is to "determine if there are any issues that would potentially rebut the presumption of adequate protection provided by the licensee meeting the deterministic requirements and regulations." The staff has reviewed Entergy's assessment of risk at the proposed EPU conditions and compared the VY probabilistic risk assessment (PRA) results with the staff's SPAR model results for this plant. The values of core damage frequency (CDF) and large early release frequency (LERF) are low and provide substantial margin to values that raise questions of adequate levels of safety. As we noted previously, the staff also used risk insights in their independent determination of the acceptability of the potential for pump cavitation during long-term core cooling in LOCA and ATWS scenarios.

This was the second application by the staff of RS-001 in the review of an EPU proposed upgrade. RS-001 provides a structured approach to the review.

Sincerely,

/RA/

Graham B. Wallis
Chairman

Additional Comments by ACRS Members Richard S. Denning, Thomas S. Kress, Victor H. Ransom, and Graham B. Wallis

Considering all the evidence, including precedents set at other similar plants, we agreed with our colleagues to approve the proposed 20% EPU for VY.

It seems unlikely that there will be a problem with adequate NPSH of the core spray and residual heat removal (RHR) pumps at Vermont Yankee, with a 20% power uprate. However, we were asked to make a professional judgment that would have been more straightforward if the information supplied to us had been more complete. We suspect that more information already exists that could be reorganized, supplemented as needed, and presented logically to provide a more convincing case in the following way, which would set a better precedent for future applications:

1. Derive sufficient detail of the probability distribution for containment pressure following large LOCA and ATWS sequences, based on realistic analysis of the physical phenomena and the attendant uncertainties.

2. Derive sufficient detail of the probability distribution for suppression pool temperature following these events, based on realistic analysis of the physical phenomena and the attendant uncertainties.

3. Combine the results of steps 1 and 2 with realistic and uncertainty analyses of other phenomena influencing NPSH to derive the probability of successful operation of RHR and core spray pumps. This may provide adequate evidence for a conclusion to be reached, if it can be shown that only a small containment overpressure is likely to be needed for a short time, if at all, and it has a high probability of being available. If further evidence is required, these results can be incorporated into the PRA to derive the realistic contribution, if any, to total plant risk due to insufficient NPSH.

Both Entergy and the staff have shown that relaxing a few of the many conservatisms and using realistic values (for example, of the initial temperature of the suppression pool) removes the need for additional NPSH. Such arguments are insufficiently conclusive. The reason is that when one gives up an element of conservatism, without replacing it by a less stringent assumption that is still demonstrably conservative, there is a finite probability that values of the derived parameter will not bound all possibilities. The proper way to relax the many conservative assumptions is to make (some of) them realistic with the inclusion of uncertainty. This will lead to a probability distribution (or more precisely some aspects of it, such as the 95/95 confidence level) for an output such as pool temperature.

From the analyses that we have seen in presentations by Entergy and by the staff, it appears likely that the realistic contribution to risk from inadequate RHR and core spray pump NPSH will prove to be very small, even essentially zero, for the case of the proposed power uprate at VY, but this could be better demonstrated in a manner which is both physically and logically consistent. The probabilities associated with the governing physical phenomena may be regarded as more secure than some other inputs to the usual PRA assessment. Conclusions based on them may help to convince those who doubt if conventional risk-based arguments alone should allow the relaxation of defense-in-depth that is achieved by the independence of cladding and containment barriers to radioactivity release. In particular, if it can be shown that the probability of needing containment overpressure is sufficiently small, the independence of these barriers would effectively be preserved.

<u>REFERENCES:</u>

1. Memorandum from Ledyard B. Marsh to John Larkins, "Vermont Yankee Nuclear Power Station - Draft Safety Evaluation for the Proposed Extended Power Uprate (TAC No. MC0761)", October 21, 2005

2. Letter from Wayne Lanning to Jay Thayer, "Vermont Yankee Nuclear Power Station, NRC Inspection Report 05000271/2004008", December 2, 2004

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* See previous concurrence.

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