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NUCLEAR REGULATORY COMMISSION

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OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

Before the Atomic Safety and Licensing Board

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

ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF NEW ENGLAND COALITION CONTENTION 3

Applicants Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (collectively "Entergy") file this motion, pursuant to 10 C.F.R. §2.1205(a)[1] and the Atomic Safety and Licensing Board's ("Board") Memorandum and Order, LBP-04-28 (Nov. 22, 2004),[2] to seek dismissal by summary disposition of the New England Coalition's ("NEC") Contention 3 in this proceeding ("NEC Contention 3"). Entergy seeks summary disposition of the contention on the grounds that no genuine issue as to any material fact exists and Entergy is entitled to a decision as a matter of law. This motion is supported by a Statement of Material Facts as to which Entergy asserts there is no genuine dispute and the Declaration of Craig J. Nichols ("Nichols Declaration").

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1 10 C.F.R. §2.1205(a) states: "(a) Unless the presiding officer or the Commission directs otherwise, motions for summary disposition may be submitted to the presiding officer by any party no later than forty-five (45) days before the commencement of hearing. The motions must be in writing and must include a written explanation of the basis of the motion, and affidavits to support statements of fact. Motions for summary disposition must be served on the parties and the Secretary at the same time that they are submitted to the presiding officer."

2 Memorandum and Order, LBP-04-28, 60 NRC 548 (2004).

Template = SECY-041 SECY-02

I. STATEMENT OF FACTS

One of the contentions originally proposed by NEC was Contention 3, which asserts that Entergy's application for an extended power uprate ("EPU") for the Vermont Yankee Nuclear Power Station ("VY") ("Application") should not be approved unless performance of Large Transient Testing ("LTT") is a made a condition of the uprate.[3]

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" defines the Main Steam Isolation Valve ("MSIV") Closure and the Generator Load Rejection tests as the LTT applicable to VY.[4] NRC's Review Standard RS-001, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) references the Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," for the testing related to extended power uprates. SRP 14.2.1 specifies that LTT is to be performed in a similar manner to the testing that was performed during initial startup testing of the plant. The SRP also provides guidance on how to justify a request for deletion of the LTT requirement.[5]

In accordance with the SRP guidance, Entergy included in its Application a separate attachment devoted to discussing the bases for an exception to performing LTT at VY in connection with the proposed EPU.[6] In that attachment, Entergy addressed factors that justify 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.

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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." 60 NRC at 580, Appendix 1.

[4] Nichols Declaration, ¶ 8.

[5] *Id.*, ¶ 11. A copy of SRP 14.2.1 is attached as Exhibit 2 to the Nichols Declaration.

[6] Application, Att. 7, "Justification for Exception to Large Transient Testing" ("Justification"). Entergy subsequently supplemented its justification discussion. *See*, Application, Supplement 3, Att. 2 (Oct. 28, 2003). Copies of these materials are included as Exhibits 3 and 4 to the Nichols Declaration.

The Board's rationale for admitting NEC Contention 3 was twofold: (1) the LTT exception request was part of the EPU Application and was consequently within the scope of this proceeding, and (2) NEC had submitted in support of its proposed contention a declaration by its consultant Arnold Gundersen[7] which the Board determined set forth an " expert opinion, supported by specific references to the EPU application and citations to relevant Staff documents, [which] provides a concise statement of the alleged facts or expert opinions which support NEC's position."[8] As will be seen, the statements by Mr. Gundersen are refuted by conclusive technical evidence and do not warrant the holding of a hearing on this contention.

II. ENTERGY IS ENTITLED TO SUMMARY DISPOSITION

A. Legal Standards for Summary Disposition

Commission regulations provide for summary disposition. Motions for summary disposition in a 10 C.F.R. Part 2, Subpart L, proceeding may be submitted up to 45 days before the commencement of a hearing, unless the presiding officer orders otherwise. 10 C.F.R. §2.1205(a).[9] In ruling on motions for summary disposition, the Board is to apply the standards for summary disposition set forth in subpart G of 10 C.F.R. Part 2. *Id.* §2.1205(c). The standards for summary disposition under Subpart G are set forth in 10 C.F.R. §2.710, which states that the "presiding officer shall render the decision sought if . . . there is no genuine issue as to any material fact and . . . the moving party is entitled to a decision as a matter of law." *Id.,* §2.710(d)(2). The Commission's requirements for summary disposition are satisfied with respect to NEC Con-

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7 Declaration of Arnold Gundersen in Support of Petitioners' Contention (August 30, 2004) ("Gundersen Declaration"), Attachment D to New England Coalition's Request for Hearing, Demonstration of Standing, Discussion of Scope of Proceeding and Contentions" (Aug. 30, 2004).

8 LBP-04-28, 60 NRC at 572.

9 In its Initial Scheduling Order, the Board set 30 days after the issuance by the Staff of the Draft Safety Evaluation Report for the EPU ("Draft SER") as the deadline for filing motions for summary disposition herein. Initial Scheduling Order (Feb. 1, 2005) at 3. The draft was posted on ADAMS on November 2, 2005 (Accession Number ML053010167).

tention 3 because there is no genuine issue of disputed fact that would require a hearing and Entergy is entitled to a favorable decision as a matter of law.

Under the NRC Rules of Practice, a moving party is entitled to summary disposition of a contention as a matter of law if the filings in the proceeding, together with the statements of the parties and the affidavits, demonstrate that there is no genuine issue as to any material fact. The Rules "long have allowed summary disposition in cases where there is no genuine issue as to any material fact and where the moving party is entitled to a decision as a matter of law." *Carolina Power & Light Co.* (Shearon Harris Nuclear Power Plant), CLI-01-11, 53 NRC 370, 384 (2001) (internal quotations omitted); *Advanced Medical Sys., Inc.* (One Factory Row, Geneva, Ohio), CLI-93-22, 38 NRC 98, 102-03 (1993). Commission case law is clear that for there to be a genuine issue, "the factual record, considered in its entirety, must be enough in doubt so that there is a reason to hold a hearing to resolve the issue." *Cleveland Electric Illuminating Co.* (Perry Nuclear Power Plant, Units 1 and 2), LBP-83-46, 18 NRC 218, 223 (1983). Summary disposition "is a useful tool for resolving contentions that . . . are shown by undisputed facts to have nothing to commend them." *Private Fuel Storage, L.L.C.* (Independent Fuel Storage Installation), LBP-01-39, 54 NRC 497, 509 (2001).

Those principles apply here. Lacking any genuine factual dispute, NEC Contention 3 clearly has "nothing to commend" it for further litigation in this proceeding and should be dismissed.

B. There Is No Factual Dispute Requiring Litigation

In his Declaration, Mr. Gundersen raised without much elaboration three reasons why the justification provided by Entergy for deleting the LTT requirement was insufficient:

- Operational experience does not provide adequate support for the exception being sought.[10]
- VY's successful experience with full power transients at 100% level does not demonstrate the performance at 120% level.[11]
- Component testing does not obviate the need for full power testing of the transients.[12]

None of these claims has a defensible factual basis. Thus, there remains no genuine issue as to any material fact relevant to NEC Contention 3.

1. <u>The analytical tools used by Entergy will accurately predict plant performance in large transient events under EPU conditions</u>

The transient analyses for VY are performed using the NRC-approved code ODYN, which models the behavior of the safety- and non-safety-related systems of the plant during operational events.[13] These analytical tools have been accepted by the NRC Staff.[14] The transient analyses for VY include the two LTT events.[15] Neither NEC nor its consultant Mr. Gundersen has challenged the validity of the VY analytical tools or their results.

The transient analyses for VY model both the performance of the secondary side of the plant and any potential interactions between primary and secondary systems in a transient.[16] The analyses assume operational configurations and component/system failures that bound (i.e., rep-

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[10] Gunderson Declaration at 4.

[11] *Id.*

[12] *Id.* at 5.

[13] Nichols Declaration, ¶ 16.

[14] *Id.*

[15] *Id.*

[16] *Id.*, ¶ 17.

resent more severe conditions than) the transients that would occur during actual EPU plant operations or during LTTs.[17]

While some of the plant operating parameters (e.g., core power distribution) will be modified to accommodate higher power operation after EPU, none of the plant modifications that have been or will be made for the EPU will introduce new thermal-hydraulic phenomena, nor will there be any new system interactions during or as the result of analyzed transients introduced.[18] Nor will there be any impairment of the safety function of components such as piping and pipe supports.[19] Accordingly, there is every reason to anticipate that the transient analyses will accurately predict the plant response to large transient events without need to perform actual LTT.[20]

2. <u>Operational experience in the United States and abroad justifies the granting of the exception</u>

There is a wealth of worldwide operational experience demonstrating that the performance of boiling water reactors ("BWRs") such as VY during transients matches the predictions of analytical tools used by Entergy and other utilities to analyze those transients. Examples include:

1. Southern Nuclear Operating Company's (SNOC) application for EPU of Hatch Units 1 and 2 was granted without requirements to perform large transient testing. VY and Hatch are both BWR/4 plants with Mark I containments.[21]

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[17] *Id.*

[18] *Id.*, ¶ 18.

[19] *Id.*, ¶ 19.

[20] *Id.*, ¶ 20.

[21] *Id.*, ¶ 21.

2. Hatch Unit 2 experienced a post-EPU unplanned event that resulted in a generator load rejection from approximately 111% Original Licensed Thermal Power ("OLTP") (98% of uprated power) in May 1999. All systems functioned as expected and there were no anomalies were seen in the plant's response to this event. [22]

3. Hatch Unit 2 also experienced post-EPU reactor trip on high reactor pressure as a result of MSIV closure (from 113% OLTP (100% of uprated power)) in 2001. Systems functioned as expected and designed, given the conditions experienced during the event.[23]

4. Hatch Unit 1 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.[24]

5. Progress Energy's Brunswick Units 1 and 2 were licensed to 120% of OLTP and was granted the license amendment without requirements to perform LTT. VY and Brunswick are BWR/4 plants with Mark I containments. Brunswick Unit 2 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 response was observed.[25]

6. 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. VY, Quad Cities and Dresden units are similar plants with Mark I containments. Dresden 3

[22] SNOC's LER 1999-005-00, attached as Exhibit 6 to the Nichols Declaration.

[23] SNOC's LER 2001-003-00, attached as Exhibit 7 to the Nichols Declaration.

[24] SNOC's LERs 2000-004-00 and 2001-002-00, attached as Exhibits 8 and 9 to the Nichols Declaration.

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). The plant response was as expected and no new plant behaviors were observed.[26]

7. 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). Plant response was as anticipated.[27]

8. The Kernkraftwerk (KKL) plant in Leibstadt, Switzerland had an EPU from 104.2% to 116.7% OLTP which was performed during the period from 1995 to 2000. Power was raised in steps, and LTT was performed at 110.5% OLTP in 1998, 113.5% OLTP in 1999 and 116.7% OLTP 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. [28]

In its draft SER, the NRC reviewed this operational experience and concluded:

> 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

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Footnote continued from previous page

[25] Progress Energy's LER 2003-004-00, attached as Exhibit 10 to the Nichols Declaration.

[26] See Exhibits 11 and 12 to the Nichols Declaration.

[27] See Exhibit 13 to the Nichols Declaration.

[28] Nichols Declaration, ¶¶ 25-26.

> 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.
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> 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.

Draft SER at 265-66. Thus, as the NRC Staff determined in the SER, "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 agreement between analytical predictions and the transient performance of these planned and unplanned transients in plants similar in design to VY is fully applicable and demonstrates that the analytical methods used by Entergy to evaluate the plant response to LTT can accurately predict the response without need to conduct actual testing.[29]

[29] Mr. Gundersen cited a request for additional information issued by the NRC Staff in the Duane Arnold EPU application, which asked the applicant to address how the operating experience at the Hatch Unit 1 and 2 demonstrates that transient analyses for the Duane Arnold plant would provide equivalent protection compared to the LTT. Gunderson Declaration at 4. However, the Staff ultimately agreed that reliance on the Hatch experience was relevant and probative of the ability of the Duane Arnold plant to predict the response of the plant's systems to large transients and concluded that "[n]o new plant behaviors have been observed that would indicate that the analytical models being used are not capable of modeling plant behavior at the EPU conditions." Letter dated March 17, 2005 from Deirdre W. Spaulding (NRC) to Mark A. Peifer (Duane Arnold Energy Center), Attachment 2 at 11, copy included as Exhibit 14 to the Nichols Declaration.

3. The VY Operational Experience Justifies the Requested Exception

Mr. Gundersen dismisses VY's operational experience as the basis for the proposed exception in two sentences: "Entergy argues that Vermont Yankee has experienced full power load rejections at 100% power and that no significant anomalies were seen. How this bears on performance at 120% power is somewhat of a mystery."[30] It is, however, hardly a mystery. The operational experience of VY at its current licensed power level is very relevant to how the plant is expected to perform in transients from EPU operation.

The VY transient experience includes:

- On 3/13/91, the with reactor at full power, a reactor scram occurred as a result of Turbine/Generator rip on Generator Load Rejection due to a 345 kV Switchyard Tie Line Differential Fault. This event was reported to the NRC in LER 1991-005-00, dated 4/12/91.[31]
- On 4/23/91, with the reactor at 100% 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 event included a loss of offsite power. This was reported to the NRC in LER 1991-009-00, dated 05/23/91.[32]
- On 6/15/91, during normal operation with reactor power at 100% 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 event was reported to the NRC in LER 1991-014-00, dated 7/15/91.[33]
- On 6/18/2004, during normal operation with the reactor at 100% 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

[30] Gunderson Declaration at 5.

[31] Nichols Declaration, Exhibit 16.

[32] *Id.*, Exhibit 17.

[33] *Id.*, Exhibit 18.

Rejection reactor scram. This event was reported to the NRC in LER 2004-003-00, dated 8/16/2004.[34]

- 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 event was reported to the NRC in LER 2005-001-00.[35]

Significantly, most of the modifications associated with the EPU, 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 were already installed at the time of these two transients.[36] In each instance, the modified or added equipment functioned normally during the transient.[37]

VY performed as expected in response to all the transients. No significant anomalies were seen in the plant's response to the events. The performance of VY in the transients it experienced at current power levels was well within the bounds of analyzed VY response.[38] 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. Also, the VY EPU is performed without a change in operating reactor dome pressure from current plant operation. Therefore, there is no basis for the transient performance of the plant under EPU to be outside the NRC Staff accepted experience base for EPU.[39]

In its draft SER, the NRC Staff has concluded that the VY operating experience supports the granting of the LTT exclusion:

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[34] *Id.*, Exhibit 19.

[35] *Id.*, Exhibit 20.

[36] Nichols Declaration, ¶ 29.

[37] *Id.*

[38] *Id.*, ¶ 30.

[39] *Id.*, ¶ 31.

> Another factor used 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, 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.

Draft SER at 266.

4. <u>Component testing at VY provides assurance that the plant's safety systems will operate as intended during transient conditions</u>

In its Application, Entergy explained that the important nuclear characteristics required for transient analysis are confirmed by the steady state testing of systems and components.[40] Mr. Gundersen dismissed, without elaboration, the applicability of component testing as a predictor of system performance during transients. There is no basis for such a dismissal. Surveillance testing performed during normal plant operations confirms the important performance characteristics required for appropriate transient response.[41] Technical Specification-required surveillance testing (e.g., component testing, trip logic system testing, simulated actuation testing) demonstrates that the systems, structures and components ("SSCs") will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis.[42] For example, 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 is tested quarterly, assuring that it will carry out its design function in the event of a large transient.[43]

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[40] See Justification at 2.

[41] Nichols Declaration, ¶ 33.

[42] *Id.*

[43] *Id.*, ¶ 34.

The characteristics and functions of SSCs do not need to be demonstrated further in a large transient test.[44] In addition, limiting transient analyses (i.e., those that affect core operating and safety limits) are reperformed each cycle and are included as part of the reload licensing analysis.[45]

In the Draft SER, the NRC credits the steady-state testing program conducted by Entergy:

> 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.

Draft SER at 267. Except for requesting the performance of additional condensate and feedwater system transient testing (to which Entergy has agreed), the Staff accepted Entergy's steady-state testing program as a predictor of plant performance during transients. NEC has offered no arguments to the contrary.

C. Entergy is Entitled to a Favorable Decision as a Matter of Law

There is no genuine issue on a material fact regarding NEC Contention 3 that could result in the denial of Entergy's application. Accordingly, Entergy is entitled to summary disposition of the contention as a matter of law.

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[44] *Id.*, ¶ 35.

[45] *Id.*

III. CONCLUSION

As demonstrated above, none of the objections to the LTT exclusion raised by NEC and its consultant in Contention 3 has any factual merit. Accordingly, there is no genuine dispute of material fact remaining to litigate and Entergy is entitled to a decision as a matter of law on NEC Contention 3.

CERTIFICATION

In accordance with 10 C.F.R. §2.323(b), counsel for Entergy has discussed this motion with counsel for the other parties in this proceeding in an attempt to resolve this issue.

Respectfully submitted,

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Dated: December 2, 2005

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

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

STATEMENT OF MATERIAL FACTS REGARDING NEC CONTENTION 3 ON WHICH NO GENUINE DISPUTE EXISTS

Applicants Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (collectively "Entergy") submit, in support of their motion for summary disposition of NEC Contention 3, that there is no genuine issue to be heard with respect to the following material facts.

1. On August 30, 2004, the New England Coalition ("NEC") sought admission, *inter alia*, of its Contention 3 ("NEC Contention 3"). New England Coalition's Request For Hearing, Demonstration of Standing, Discussion of Scope of Proceeding and Contentions, dated August 30, 2004 at 11.

2. 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."

3. 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"). Declaration of Craig J. Nichols ("Nichols Declaration"), ¶ 7.

4. Implementation of the guidance in NEDC-33004P-A results in an increase in reactor power without an increase in plant operating pressure (*i.e.*, a "constant pressure power uprate"). Nichols Declaration, ¶ 7.

5. NEDC-33004P-A defines two Large Transient Tests ("LTTs") applicable to EPU operations: the Main Steam Isolation Valve ("MSIV") Closure and the Generator Load Rejection tests. Nichols Declaration, ¶ 8.

6. These tests, when conducted during EPU operation, are similar to counterpart tests performed during initial plant startup testing. Nichols Declaration, ¶ 8.

7. NRC's Review Standard RS-001, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) references to Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," for the testing related to extended power uprates. Nichols Declaration, ¶ 11.

8. SRP 14.2.1 specifies that LTT is to be performed in a similar manner to the testing that was performed during initial startup testing of the plant. Nichols Declaration, ¶ 11.

9. The SRP also provides guidance on how to justify a request for elimination of the LTT requirement. Nichols Declaration, ¶ 11.

10. Entergy has followed the SRP guidance in taking exception to performing LTT during EPU operations at VY. Nichols Declaration, ¶ 12.

11. On November 2, 2005 the NRC Staff issued its draft Safety Evaluation Report ("Draft SER"), in which the Staff concluded that the requested exception from LTT at VY should be granted. Exhibit 5 to Nichols Declaration.

12. The transient analyses for VY were performed using the NRC-approved code ODYN, which models the behavior of the safety- and non-safety-related systems of the plant during operational events. Nichols Declaration, ¶ 16.

13. The transient analyses for VY had been accepted by the NRC Staff. Nichols Declaration, ¶ 16.

14. The transient analyses of record for VY include the two LTT events. Nichols Declaration, ¶ 16.

15. The transient analyses for VY model both the performance of the secondary side of the plant and any potential interactions between primary and secondary systems in a transient. Nichols Declaration, ¶ 17.

16. The transient analyses for VY assume operational configurations and component/system failures that bound (i.e., represent more severe conditions than) the transients that would occur during actual EPU plant operations or during LTTs. Nichols Declaration, ¶ 17.

17. While some of the plant operating parameters (e.g., core power distribution) will be modified to accommodate higher power operation after EPU, none of the plant modifications that have been or will be made for the EPU will introduce new thermal-hydraulic phenomena, nor will there be any new system interactions during or as the result of analyzed transients introduced. Nichols Declaration, ¶ 18.

18. As part of the EPU analyses, Entergy evaluated the increase in main steam flow resulting from EPU operation and its effect on the loadings on piping and pipe supports during large transients. Entergy's analyses determined that the loadings on piping and pipe supports during large transients at EPU power levels are within acceptable bounds. Entergy's evaluation of the performance of piping and pipe supports was reviewed and accepted by the NRC Staff. Draft SER § 2.2.1 at 29.

19. Since the analyses assume operational configurations and component/system failures that bound the transients that would occur during actual EPU operations and since no changes will be made to the plant that could be reasonably anticipated to introduce new thermal-hydraulic phenomena or give rise to any new system interactions during the transients, there is every reason to anticipate that the transient analyses will accurately predict the plant response to large transient events without need to perform actual LTT. Nichols Declaration, ¶ 20.

20. Thirteen boiling water reactor ("BWR") plants similar to VY have implemented EPUs without increasing operating 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% OLTP)

Nichols Declaration, ¶ 14.

21. Of the thirteen BWR plants analogous to VY 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. Nichols Declaration, ¶ 21.

22. In every instance in which unplanned large transient power levels have been experienced at those four plants, the plant's response matched the analytical predictions and exhibited no new phenomena. Nichols Declaration, ¶ 22.

23. The analytical tools used to predict the performance of those plants during transients are the same as those used at VY. Nichols Declaration, ¶ 22.

24. The KKL plant in Leibstadt, Switzerland performed LTT as part of its EPU implementation. Nichols Declaration, ¶ 25.

25. The Leibstadt LTT results matched the analytical predictions and identified no anomalous plant behavior. Nichols Declaration, ¶ 26.

26. The analytical tools used to predict the performance of the Leibstadt plant during transients are the same as those used at VY. Nichols Declaration, ¶ 26.

27. In the draft SER, the NRC Staff concluded that the experience at the plants that have undergone large unplanned transients shows that "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." Draft SER at 266.

28. In the draft SER, the NRC Staff concluded that the Leibstadt LTT program results "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." Draft SER at 266.

29. In approving the EPU application for the Duane Arnold Energy Center, the NRC Staff concluded that "[n]o new plant behaviors have been observed that would indicate that the analytical models being used are not capable of modeling plant behavior at the EPU conditions." Letter dated March 17, 2005 from Deirdre W. Spaulding (NRC) to Mark A. Peifer (Duane Arnold Energy Center), Attachment 2 at 11, Exhibit 14 to the Nichols Declaration.

30. During its operation at current licensed power levels, VY has experienced the following unplanned transients: (1) On 3/13/91, the with reactor at full power, a reactor scram occurred as a result of Turbine/Generator rip on Generator Load Rejection due to a 345 kV Switchyard Tie Line Differential Fault. This event was reported to the NRC in LER 1991-005-00, dated 4/12/91. (2) On 4/23/91, with the reactor at 100% 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 event included a loss of offsite power. This was reported to the NRC in LER 1991-009-00, dated 05/23/91. (3) On 6/15/91, during normal operation with reactor power at 100% 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 event was reported to the NRC in LER 1991-014-00, dated 7/15/91. (4) On 6/18/2004, during normal operation with the reactor at 100% 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 event was reported to the NRC in LER 2004-003-00, dated 8/16/2004. (5) 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 event was reported to the NRC in LER 2005-001-00. Nichols Declaration, ¶ 28.

31. Most of the modifications associated with EPU, 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 were already installed at the time of the most recent (August 2004 and July 2005) transients. Nichols Declaration, ¶ 29. In each instance, the modified or added equipment functioned normally during the transient. *Id.*

32. VY performed as expected in response to all the transients. No significant anomalies were seen in the plant's response to the events. Nichols Declaration, ¶ 30.

33. The performance of VY in the transients it experienced at current power levels was well within the bounds of analyzed VY response. Nichols Declaration, ¶ 30.

34. 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. Also, the VY

EPU is performed without a change in operating reactor dome pressure from current plant operation. Nichols Declaration, ¶ 31.

35. There is no basis for the transient performance of the plant under EPU to be outside the NRC Staff accepted experience base for EPU. Nichols Declaration, ¶ 31.

36. In the draft SER, the NRC made the following determination with respect to the large transient experience at VY: "Another factor used 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." Draft SER at 266.

37. Technical Specification-required surveillance testing (e.g., component testing, trip logic system testing, simulated actuation testing) performed during plant operations demonstrates that the systems, structures and components ("SSCs") required for appropriate transient performance will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis. Nichols Declaration, ¶ 33.

38. 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 is tested quarterly, assuring that it will carry out its design function in the event of a large transient. Nichols Declaration, ¶ 34.

39. 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. Nichols Declaration, ¶ 35.

40. The performance of a scram from high power as those occurring during LTT results is a transient cycle on the primary system. Nichols Declaration, ¶ 37.

41. Primary system transient cycles should be avoided if at all possible, since they introduce unnecessary stresses on the primary system. Nichols Declaration, ¶ 37.

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)

CERTIFICATE OF SERVICE

I hereby certify that copies of "Entergy's Motion for Summary Disposition of New England Coalition Contention 3," "Statement of Material Facts Regarding NEC Contention 3 on Which no Genuine Dispute Exists," and "Declaration of Craig J. Nichols" 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 2nd day of December, 2005.

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Matias F. Travieso-Diaz

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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)	)	

DECLARATION OF CRAIG J. NICHOLS

Craig J. Nichols states as follows under penalties of perjury:

I. Introduction

1. I am Extended Power Uprate Project Manager for Entergy Nuclear Operations, Inc. ("Entergy"), and I am the manager for the proposed extended power uprate ("EPU") at the Vermont Yankee Nuclear Power Station ("VY"). I am providing this declaration in support of Applicant's Motion or Summary Disposition of New England Coalition's ("NEC") Contention 3 ("NEC Contention 3") in the above captioned proceeding.

2. My professional and educational experience is summarized in the *curriculum vitae* attached as Exhibit 1 to this declaration. 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 proposed EPU at VY.

3. In my capacity as manager for the VY EPU project, I am responsible for overseeing the plant modifications that are 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.

4. In NEC Contention 3, as admitted, NEC asserts that: "The license amendment should not be approved unless Large Transient Testing is a condition of the Extended Power Uprate." In this Declaration, I will address this contention and demonstrate it lacks technical or factual basis.

5. In particular, I will demonstrate that, based on the (a) similarity of the VY design configuration and system functions at pre-EPU to post-EPU; (b) results of past transient testing at VY and the plant's responses to unplanned transients; (c) the close correlation between past transient and safety analyses and the results from actual transients; and (d) the experience with planned and unplanned transients at other post-EPU plants, the effects of transients at EPU conditions at VY can be accurately predicted analytically without the need for actual transient testing. The transient analyses performed for the VY EPU demonstrate that all safety criteria are met and that the uprate does not cause any previous non-limiting events to become limiting. On the other hand, a scram from EPU power levels -- such as those that would occur during LTT -- would cause an undesirable transient cycle on the primary system. Such transients should be avoided if possible.

II. Background on Large Transient Testing

6. In its license amendment application to increase VY's authorized power level from 1593 megawatts thermal ("MWt") to 1912 MWt, Entergy seeks to be exempted from performing Large Transient Testing ("LTT"). NEC Contention 3 asserts that LTT must be conducted to assure that public health and safety is protected during EPU operations and that the EPU should not be approved unless LTT is required to be performed.

7. The VY EPU request was prepared following the guidelines contained in the NRC-approved document "General Electric Company Licensing Topical Report for Constant Pressure Power Uprate Safety Analysis (CLTR): 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 plant operating pressure (*i.e.*, a "constant pressure power uprate.")

8. 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. Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs" (Draft, 2002) ("SRP 14.2.1"), Section III.C.2.f.

9. Closure of all MSIVs 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. 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. The transient produced by an MSIV closure test is the most severe abnormal operational transient from the standpoint of increase in nuclear system pressure.

10. A Generator Load Rejection From High Power Without Bypass ("GLRWB") (commonly referred to as generator load rejection) is also an Abnormal Operational Transient as described in Chapter 14 of the UFSAR. The GLRWB analysis assumes that the transient is initiated by a rapid closure of the turbine control valves (after a load rejection). It also assumes that all bypass valves fail to open. The purpose of this test is to 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. A GLRWB is the most severe transient in terms of challenge to the fuel thermal limits.

11. NRC's Review Standard RS-001, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) references SRP 14.2.1 for the testing related to extended power uprates. The SRP, in turn, specifies that LTT is to be performed in a similar manner to the testing that was performed during initial startup testing of the plant. The SRP also provides guidance on how to justify a request for elimination of the LTT requirement. Previous operating experience and the introduction of no new thermal-hydraulic phenomena or unanalyzed system interactions are among the factors that the Staff will take into account in evaluating such a request. SRP 14.2.1, Section III. C.2. A copy of SRP 14.2.1 is included as Exhibit 2 hereto.

12. Entergy followed the SRP guidance in taking exception to performing LTT during EPU operations at VY. Entergy included in its Application a separate attachment discussing the

bases for an exception to performing LTT at VY in connection with the proposed EPU.[1] The basis for seeking an exception to the LTT requirement is 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 and would impose additional and unnecessary transient cycles on the primary system.

13. On November 2, 2005 the NRC Staff issued its draft Safety Evaluation Report ("Draft SER"), in which the Staff concluded that the requested exception from LTT at VY should be granted. Specifically, the Staff concluded that "in justifying test eliminations or deviations, other than the condensate and feedwater 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 from the KKL plant, and experience gained from actual plant transients experienced in 1991 at the VYNPS." The Staff concluded: "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. The staff also noted that the licensee followed NRC staff approved GE topical report guidance which was developed for the VYNPS EPU licensing application." Relevant excerpts from the Draft SER are attached as Exhibit 5 hereto.

14. Thirteen boiling water reactor ("BWR") plants similar to VY have implemented or are implementing EPUs without increasing operating 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 119.7% OLTP)
- Duane Arnold (105% to 120% OLTP)
- Brunswick Units 1 and 2 (105% to 120% OLTP)

[1] Application, Att. 7, "Justification for Exception to Large Transient Testing" ("Justification"). Entergy subsequently supplemented its justification discussion. *See*, Application, Supplement 3, Att. 2 (Oct. 28, 2003). Copies of these materials are included as Exhibits 3 and 4 hereto.

- Quad Cities Units 1 and 2 (100% to 117% OLTP)
- Dresden Units 2 and 3 (100% to 117% OLTP)
- Clinton (100% to 120% OLTP).

15. There is a wealth of operational experience on the performance of these plants under unplanned large transients, as well as under LTT. I will discuss that experience below.

III. <u>Adequacy of the analytical tools used by Entergy to accurately predict plant performance in large transient events under EPU conditions</u>

16. The transient analyses for VY were performed using the NRC-approved code ODYN, which models the behavior of the safety- and non-safety-related systems in the plant during operational events. The transient analyses for VY have been accepted by the NRC Staff. The transient analyses for VY include the two large transients for which LTT is required.

17. The transient analyses for VY model both the performance of the secondary side of the plant and any potential interactions between primary and secondary systems in a transient. The analyses assume operational configurations and component/system failures that bound (i.e., represent more severe conditions than) the transients that would occur during actual EPU plant operations or during LTTs.

18. While some of the plant operating parameters (e.g., core power distribution) will change to accommodate higher power operation after EPU, none of the plant modifications made for the EPU will introduce new thermal-hydraulic phenomena, nor will there be any new system interactions during or as the result of analyzed transients.

19. As part of the EPU analyses, Entergy evaluated the increase in main steam flow resulting from EPU operation and its effect on the loadings on piping and pipe supports during large transients. Entergy's analyses determined that the loadings on piping and pipe supports during large transients at EPU power levels are within acceptable bounds. Entergy's evaluation of the performance of piping and pipe supports was reviewed and accepted by the NRC Staff. Draft SER § 2.2.1 at 29.

20. Since the analyses assume operational configurations and component/system failures that bound the transients that would occur during actual EPU operations and since no changes

will be made to the plant that could introduce new thermal-hydraulic phenomena or give rise to any new system interactions during the transients. Therefore, the transient analyses accurately predict the plant response to large transient events without need to perform actual LTT.

IV. Operational experience at plants in the United States and abroad that have implemented EPUs

21. 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 event 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 6), all systems functioned as expected and no anomalies were seen in the plant's response to this event.

- 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 7), systems functioned as expected and designed, given the conditions experienced during the event.

- 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 8 and 9). 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.

- Progress Energy's Brunswick Units 1 and 2 were licensed to 120% of OLTP and were granted the license amendments without a requirement to perform LTT. VY and

Brunswick are BWR/4 plants with Mark I containments. Brunswick Unit 2 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. As noted in Progress Energy's LER 2003-004-00 (attached as Exhibit 10), no anomalies were experienced in the plant's response to this event, 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 similar plants 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 11 and 12). The plant response was as predicted in the transient analyses, which use 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). Exelon LER 2004-003-00, attached as Exhibit 13.

22. In every instance in which unplanned large transient power levels have been experienced at these four plants, the plant's response was similar to the analytical predictions and exhibited no new phenomena. The analytical tools (i.e., the ODYN code) used to predict the performance of these plants to the transients are the same used by Entergy at VY.

23. During its review of the EPU application for the Duane Arnold Energy Center, the NRC Staff inquired about the applicability of operational experience at other plants to Duane

Arnold. Ultimately, however, the NRC Staff concluded that the operational experience showed that "[n]o new plant behaviors have been observed that would indicate that the analytical models being used are not capable of modeling plant behavior at the EPU conditions." Letter dated March 17, 2005 from Deirdre W. Spaulding (NRC) to Mark A. Peifer (Duane Arnold Energy Center), Attachment 2 at 11, Exhibit 14 hereto.

24. Likewise, in its Draft SER, the NRC Staff concluded that the experience at the plants that have undergone large unplanned transients shows that "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." Draft SER at 265-66.

25. 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. See Exhibit 15 hereto.[2]

26. These large transient tests at KKL demonstrated the response of the equipment and the reactor response. The close correlation to the predicted response (which was obtained using the same analytical tools employed at VY) provides additional confidence that the uprate licensing analyses consistently reflected the behavior of the plant.

27. In the draft SER, the NRC Staff concluded that the Leibstadt LTT program results "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." Draft SER at 266.

[2] The attachments to Exhibit 15 are proprietary and are not included.

V. VY Operational Experience

28. VY has experienced a number of unplanned large transients during its operating history:

- 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 event was reported to the NRC in LER 1991-005-00, dated 4/12/91 (attached as Exhibit 16).

- 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 event included a loss of offsite power. This was reported to the NRC in LER 1991-009-00, dated 05/23/91 (attached as Exhibit 17).

- 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 event was reported to the NRC in LER 1991-014-00, dated 7/15/91 (attached as Exhibit 18).

- 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 event was reported to the NRC in LER 2004-003-00, dated 8/16/2004 (attached as Exhibit 19).

- 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 event was reported to the NRC in LER 2005-001-00 (attached as Exhibit 20).

29. It is important to note that most of the modifications associated with EPU, 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 were already installed at the time of the June 2004 and July 25, 2005 transients. In each instance, the modified or added equipment functioned normally during the transient.

30. VY performed as expected in response to all the transients. No significant anomalies were seen in the plant's response to the events. The performance of VY in the transients it experienced at current power levels was well within the bounds of analyzed VY response.

31. 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. Also, the VY EPU is performed without a change in operating reactor dome pressure from current plant operation. Therefore, there is no basis for the transient performance of the plant under EPU to be outside the NRC Staff accepted experience base for EPU, that is, the transients described in para. 21 above.

32. In the draft SER, the NRC made the following determination with respect to the large transient experience at VY: "Another factor used 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." Draft SER at 266.

VI. <u>Role of component testing at VY in providing assurance that the plant's safety systems will operate as intended during transient condition</u>

33. 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 systems, structures and components ("SSCs") required for

appropriate transient performance will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis.

34. For example, 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 is tested quarterly, assuring that it will carry out its design function in the event of a large transient.

35. 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.

VII. Summary and Conclusions

36. My testimony in this Declaration justifies the following conclusions:

- **Previous industry operating experience**

  Operating experience at other plants that have implemented a constant pressure power uprate such as that proposed 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 the VY because of the similarity in its design to that of those plants and because the analytical methodologies are also the same.

- **Previous VY operating experience**

  Previous operating experience at VY for large transient events has shown 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 transient events 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 these recent 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., core power distribution, feedwater flow, moisture carryover) but will not result in any new thermal-hydraulic phenomena in the event of a plant transient. 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.
- **Demonstration of system and component performance through surveillance testing**
  Technical Specification-required surveillance testing, routinely performed during plant operations and during plant shutdown, demonstrates that the SSCs required for appropriate transient performance will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis.

37. The performance of a scram from high power as those occurring during LTT results is an undesirable transient cycle on the primary system. Primary system transient cycles should be avoided if at all possible, since they introduce unnecessary stresses on the primary system components. In light of the above discussed considerations, LTT is unnecessary and its undesirable effects outweigh any limited benefits that might accrue from the performance of such tests.

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

Executed on December 2, 2005.

Craig J. Nichols

Resume of Craig Joseph Nichols

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(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

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EDUCATION

BSEE (Power Systems) **1985**

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

REFERENCES

Available upon request

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.

REVIEW RESPONSIBILITIES

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. Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

1. General Discussion

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. Specific Acceptance Criteria

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. Margin Reduction in Safety Analysis Results for Anticipated Operational Occurrences

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. Guidance Contained in Vendor Topical Reports

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 l	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 l l 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.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

Extended Power Uprate, EPU, testing, test program, power ascension testing, transient testing

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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.

4

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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CORRECTED NICHOLS EXHIBIT 5

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 planned 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 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 reperforming 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 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 reperformed as part of the EPU power ascension program:

- <u>STP-11, LPRM Calibration</u>. The test is not required to be re-performed since calibration of LPRMs, which is maintained by TSs, is not affected by EPU.
- <u>STP-13, Process Computer</u>. The test is not required to be re-performed since operation of the process computer is not affected by EPU. Plant procedures maintain the accuracy of the process computer.
- <u>STP-20, Steam Production</u>. The test is not required to be re-performed since it was only applicable for initial plant startup to demonstrate warranted capabilities.
- <u>STP-21, Response to Control Rod Motion</u>. The test is not required to be re-performed since operation at EPU 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.
- <u>STP-25, Main Steam Isolation Valves (MSIVs)</u>. 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 follows.

- 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 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, 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% power. 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 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.

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 for the KKL plant, 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. 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.

SRP 14.2.1 Section III.D
Evaluate the Adequacy of Proposed Transient Testing Plans

SRP 14.2.1 Section III.D, specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The

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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

DISCLAIMER FOR SCANNED DOCUMENTS

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

Lewis Sumner
Vice President
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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

7

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SOUTHERN COMPANY
Energy to Serve Your World℠

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 (7-2001)	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 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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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 12/25/2001 at 1819 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) 2B21-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 2B21-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.

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.

8

Lewis Sumner
Vice President
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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

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 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

POWER LEVEL (10): 99.7

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

	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 100F 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.

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 1B21-F013E and 1B21-F013J; 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 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 turbine 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 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.

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	5 OF 6

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

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: 1N3 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.

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Lewis Sumner
Vice President
Hatch Project Support

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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

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IE22

NRC FORM 366 (1-2001)	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 informatio collection request: 50 hrs. Reported lessons learned are incorporated into th licensing process and fed back to industry. Send comments regarding burde estimate to the Records Management Branch (T-6 E6), U.S. Nuclea Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail t bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulator Affairs, NEOB-10202 (3150-0104), Office of Management and Budget Washington, DC 20503. If a means used to impose information collection doe not display a currently valid OMB control number, the NRC may not conduct o sponsor, and a person is not required to respond to, the information collection.

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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.

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

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.

FACILITY NAME (1)	DOCKET	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
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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.

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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

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Ms. Jo A. Sanford
Chair - North Carolina Utilities Commission
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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.

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

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

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

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.

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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.

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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.

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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 Generation
Dresden Generating Station
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Exelon Nuclear

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,

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)

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4. TITLE Unit 3 Automatic Scram During Testing of the Main Turbine Master Trip Solenoid Valves

5. EVENT DATE MO	DAY	YEAR	6. LER NUMBER YEAR	SEQUENTIAL NUMBER	REV NO	7. REPORT DATE MO	DAY	YEAR	8. OTHER FACILITIES INVOLVED FACILITY NAME	DOCKET NUMBER
01	24	2004	2004	001	00	03	24	2004	N/A	N/A
									N/A	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.

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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.

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

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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Dresden Nuclear Power Station Unit 3	05000249	2004	001	00	4 of 4

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

Exelon Generation Company, LLC
Dresden Nuclear Power Station
6500 North Dresden Road
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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	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.

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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	10. POWER LEVEL
1	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.

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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.

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Dresden Nuclear Power Station Unit 3	05000249	2004	002	00	5 of 5

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

G. Component Failure Data:

NA

13

Exelon.
Nuclear

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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)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
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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: Dresden Unit 2	DOCKET NUMBER: 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
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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 avaliiable 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 avaliiable 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

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

March 17, 2005

Mark A. Peifer
Site Vice President
Duane Arnold Energy Center
Nuclear Management Company, LLC
3277 DAEC Road
Palo, IA 52324-0351

SUBJECT: DUANE ARNOLD ENERGY CENTER - ISSUANCE OF AMENDMENT RE: LICENSE AMENDMENT REQUEST TSCR-056, MODIFY LICENSE CONDITION 2.C.(2)(b) TO ELIMINATE MAIN STEAM ISOLATION VALVE CLOSURE TEST FOR EXTENDED POWER UPRATE (TAC NO. MC2320)

Dear Mr. Peifer:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 257 to Facility Operating License No. DPR-49 for the Duane Arnold Energy Center. This amendment consists of a change to the Operating License in response to your application dated February 27, 2004, as supplemented by letters dated August 9, 2004, and January 7, 2005.

The amendment modifies license condition 2.C.(2)(b) to remove the requirement to perform a full main steam isolation valve closure test associated with extended power uprate. In accordance with your request in letter dated January 7, 2005, licensee condition 2.C.(2)(b) to eliminate the requirement to perform a main generator load reject test is not included in this amendment and will be addressed by separate correspondence. Our review of this effort will now be performed under a separate TAC.

A copy of the Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

Deirdre W. Spaulding

Deirdre W. Spaulding, Project Manager, Section 1
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-331

Enclosures: 1. Amendment No. 257 to License No. DPR-49
2. Safety Evaluation

cc w/encls: See next page

Duane Arnold Energy Center

cc:

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Executive Vice President &
Chief Nuclear Officer
Nuclear Management Company, LLC
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Hudson, MI 54016

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November 2004

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

NUCLEAR MANAGEMENT COMPANY, LLC

DOCKET NO. 50-331

DUANE ARNOLD ENERGY CENTER

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 257
License No. DPR-49

1. The U.S. Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Nuclear Management Company, LLC (NMC) dated February 27, 2004, as supplemented by letters dated August 9, 2004, and January 7, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to paragraph 2.C.(2)(b) of Facility Operating License No. DPR-49 is hereby amended to read as follows:

   (b) The licensee will perform the generator load reject transient test required by the General Electric Licensing Topical Report for Extended Power Uprate (NEDC-32424P-A) - ELTR-1, including the allowances described in Section L.2.4 (2) of ELTR-1 regarding credit for unplanned plant transient events, using the thermal power level (1658 MWt) to establish the ELTR-1 power level limit. The testing shall be performed at an initiating power level greater than the steady-state operation power level exceeding the ELTR-1 power level limit for the generator load reject transient.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

L. Raghavan, Chief, Section 1
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Change to the Operating License

Date of Issuance: March 17, 2005

ATTACHMENT TO LICENSE AMENDMENT NO. 257

FACILITY OPERATING LICENSE NO. DPR-49

DOCKET NO. 50-331

Replace the following page of the Facility Operating License DPR-49 with the attached revised page as indicated. The revised page is identified by order number and contains marginal lines indicating the area of change.

Remove Page	Insert Page
4	4

(a) For Surveillance Requirements (SRs) whose acceptance criteria are modified, either directly or indirectly, by the increase in authorized maximum power level in 2.C.(1) above, in accordance with Amendment No. 243 to Facility Operating License DPR-49, those SRs are not required to be performed until their next scheduled performance, which is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment No. 243.

(b) The licensee will perform the generator load reject transient test required by the General Electric Licensing Topical Report for Extended Power Uprate (NEDC-32424P-A) - ELTR-1, including the allowances described in Section L.2.4 (2) of ELTR-1 regarding credit for unplanned plant transient events, using the thermal power level (1658 MWt) to establish the ELTR-1 power level limit. The testing shall be performed at an initiating power level greater than the steady-state operation power level exceeding the ELTR-1 power level limit for the generator load reject transient.

(3) Fire Protection

NMC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the Duane Arnold Energy Center and as approved in the SER dated June 1, 1978, and Supplement dated February 10, 1981, subject to the following provision:

NMC may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

(4) The licensee is authorized to operate the Duane Arnold Energy Center following installation of modified safe-ends on the eight primary recirculation system inlet lines which are described in the licensee letter dated July 31, 1978, and supplemented by letter dated December 8, 1978.

(5) Physical Protection

NMC shall fully implement and maintain in effect all provisions of the Commission- approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Nuclear Management Company Duane Arnold Energy Center Physical Security Plan, Revision 0" submitted by letter dated October 18, as supplemented by letter dated October 21, 2004.

Amendment No. ~~43, 47, 59, 63, 65, 74, 112, 152, 190, 198, 214, 223, 232, 243~~

~~Revised by Letter Dated October 28, 2004~~
~~Revised by letter dated December 10, 2004~~
Revised by letter dated March 17, 2005

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 257 TO FACILITY OPERATING LICENSE NO. DPR-49

NUCLEAR MANAGEMENT COMPANY, LLC

DUANE ARNOLD ENERGY CENTER

DOCKET NO. 50-331

1.0 INTRODUCTION

By application dated February 27, 2004, as supplemented by letters dated August 9, 2004, and January 7, 2005, the Nuclear Management Company, LLC (NMC or the licensee), requested a change to Facility Operating License No. DPR-49 for the Duane Arnold Energy Center (DAEC). The proposed change was to remove license condition 2.C.(2)(b) which requires that two specific large transient tests (LTTs) be performed at specified reactor thermal power levels, as part of power ascension testing for the extended power uprate (EPU) project at the DAEC. In a letter dated February 27, 2004, NMC requested approval of this change prior to March 1, 2005, as modifications were planned for the upcoming refuel outage at the DAEC which will allow the reactor power level to reach the license condition for performing the first of the two LTTs, the full main steamline isolation valve (MSIV) closure test. However, these planned modifications will not allow the reactor to achieve the thermal power level required to invoke the second of the two LTTs required by the license condition, namely the main generator load reject test. Given the staggered nature of the plant modifications in the DAEC EPU project, NMC's letter dated January 7, 2005, requested that the U. S. Nuclear Regulatory Commission (NRC) to issue separate license amendments, one for each of the two LTTs.

The supplemental letters contained clarifying information and did not change the initial no significant hazards consideration determination and did not expand the scope of the original *Federal Register* notice.

The NRC staff reviewed the licensee's submittals and prepared this safety evaluation (SE) that addresses the MSIV closure test provision of the DAEC Operating License. The main generator load reject test provision will be addressed in separate correspondence.

DAEC provided supplemental information concerning the elimination of license condition 2.C.(2)(b) for performance of large transient tests for EPU in a letter dated August 9, 2004, in response to an NRC staff request for additional information (RAI). In addition, the NRC staff reviewed the relevant portions of the documents listed in Section 3 of this SE. NRC staff guidance for reviewing EPU test programs is described in NUREG-0800, *Standard Review Plan* (SRP) 14.2.1, "Generic Guidelines for EPU Testing Programs," and provides reasonable assurance that the proposed testing program verifies those plant structures, systems, and components (SSCs) that are affected by the proposed power uprate will perform satisfactorily in service at the proposed power uprate level. The NRC staff review focused on the licensee adequately addressing the applicable portions of the guidance described in SRP 14.2.1 related to LTT.

In a letter dated November 6, 2001, the NRC issued Amendment No. 243 that approved the EPU for DAEC. This amendment consisted of changes to the operating license and Technical Specifications (TSs) to allow an increase in the maximum power level at DAEC from 1658 Megawatts thermal (MWt) to 1912 MWt, representing a power increase of 15.3 percent. Amendment No. 243 also added license condition 2.C.(2)(b) requiring the licensee to perform generator load reject and full MSIV closure transient tests at specified reactor thermal power levels. As discussed, the licensee's February 27, 2004, application as supplemented, is seeking two amendments that would eliminate this license condition entirely with the first amendment eliminating only the full MSIV closure test. Although the NRC staff used SRP 14.2.1, the staff noted that SRP 14.2.1 covers the entire EPU test program and a review of the licensee's overall EPU test program was performed in the SE for Amendment No. 243. Therefore, the focus of this SE is on issues related to the elimination of the performance of the full MSIV closure transient test.

License condition 2.C.(2)(b) states, "The licensee will perform the generator load reject and full main steam line isolation valve closure transients tests required by the General Electric Licensing Topical Report for Extended Power Uprate (NEDC-32424P-A)-ELTR-1, including the allowances described in Section L.2.4(2) of ELTR-1 regarding credit for unplanned plant transient events, using the thermal power level (1658 MWt) to establish ELTR-1 power level limits. The testing shall be performed at an initiating power level greater than the steady-state operation power level exceeding the respective ELTR-1 power level limit for each transient."

NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," is hereinafter referred to as ELTR-1. Following the issuance of DAEC Amendment No. 243, General Electric (GE) Company revised ELTR-1 to state that testing involving an automatic scram from a high power (which would include the DAEC generator load reject and MSIV closure tests) is not required. In a letter to GE dated March 31, 2003, the NRC took exception to GE's proposed elimination of large transient testing and stated that the NRC staff was preparing guidance to generically address the requirement for conducting large transient tests in conjunction with power uprates. The NRC subsequently provided this guidance in SRP 14.2.1. SRP 14.2.1 allows licensees to either perform the large transient tests (which would include the DAEC generator load reject and MSIV closure tests) or provide adequate technical justification for not performing the tests. To ensure consistency throughout this SE when power levels are discussed, the following table is included:

	Power Level	Date	Related Information
Original Rated Thermal Power	1593 MWt	1974	Initial plant licensed thermal power
"Current" Rated Thermal Power (CRTP)	1658 MWt	1985	

EPU Phase I	1790 MWt	December 2001	
EPU Phase II	1840 MWt	Spring 2005	1840 MWt is planned. Final achievable power level to be determined.
EPU Phase III	1912 MWt	Not yet scheduled	
Power Level in ELTR-1 for Main Steam Isolation Valve Closure Test	1823.8 MWt		Power level in ELTR-1 for test (10% of 1658 MWt).
Power Level in ELTR-1 for Generator Load Reject Test	1906.7 MWt		Power level in ELTR-1 for test (15% of 1658 MWt).

2.0 REGULATORY EVALUATION

The purpose of the EPU test program is to verify that SSCs will perform satisfactorily in service at the proposed EPU power level. The NRC staff's review covers (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, (2) integrated plant systems testing, including transient testing, if necessary, to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and (3) the test program's conformance with applicable regulations. The NRC staff's acceptance criteria for the proposed EPU test program was based, in part, on (1) Appendix B to 10 CFR Part 50, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service, (2) General Design Criterion 1, "Quality Standards and Records," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, insofar as it requires that SSCs important to safety be tested to quality standards commensurate with the importance of the safety functions to be performed, (3) 10 CFR Part 50.34, "Contents of Applications: Technical Information," which specifies requirements for the content of the original operating license application, including Final Safety Analysis Report (FSAR) plans for pre-operational testing and initial operations, and (4) Regulatory Guide (RG) 1.68, Appendix A, Section 5, "Power Ascension Tests," which describes tests that demonstrate that the facility operates in accordance with design both during normal steady-state conditions, and, to the extent practical, during and following anticipated operational occurrences (AOOs). Specific review and acceptance criteria are contained in SRP 14.2.1.

3.0 TECHNICAL EVALUATION

3.1 SRP 14.2.1 Section III.A - Comparison of Proposed Test Program to the Initial Plant Test Program

3.1.1 Evaluation Criteria of SRP 14.2.1 Section III.A

SRP 14.2.1 Section III.A, specifies the guidance and acceptance criteria that the licensee should use to compare the proposed EPU testing program to the original power ascension test program performed during initial plant licensing. The scope of this comparison should include (1) all initial power ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level, and (2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power ascension tests within the scope of this comparison or adequately justify proposed deviations from the initial power ascension test program. The following specific criteria should be identified in the EPU test program:

- 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 test program tests performed at power levels lower than 80 percent of the original licensed thermal power level that would be invalidated by the EPU, and
- differences between the proposed EPU power ascension test program and the portions of the initial test program identified by the previous criteria.

3.1.2 NRC Staff Evaluation Using SRP 14.2.1 Section III.A.

The NRC staff reviewed the licensee's Plant Uprate Safety Analysis Report for testing recommended in ELTR-1. The licensee compared the initial startup test program, and consistent with the NRC-approved generic EPU guidelines in ELTR-1, the EPU was determined to require only a limited subset of the original startup test program. As applicable to this plant's design, testing for the EPU is consistent with the description in ELTR-1. Specifically, the following testing was performed for Phase I and will be performed for Phases II and III during the power ascension steps of the EPU.

- Testing will be performed in accordance with the TS surveillance requirements on the instrumentation that requires re-calibration for the EPU conditions.
- Steady-state data will be taken at points from 90 percent up to the previous reactor thermal power so that system performance parameters can be projected for the EPU before the previous power rating is exceeded.
- Power increases beyond the previous reactor thermal power level will be made in increments of equal to or less than 5 percent power. Steady-state operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows, and vibration will be evaluated from each measurement point prior to the next power increment.
- Control system tests will be performed for the feedwater/reactor water level controls and pressure controls. These operational tests will be made at the appropriate plant conditions for each test and at each power increment above the previous rated power condition to show acceptable adjustments and operational capability. The same performance criteria will be used as in the original power ascension tests.
- A test specification will identify the EPU tests, the associated acceptance criteria, and the appropriate test conditions. All testing will be done in accordance with Appendix B to 10 CFR Part 50, Criterion XI.

The licensee's test plan follows the guidance of ELTR-1 and satisfies the applicable requirements in Appendix B to 10 CFR Part 50; therefore, the NRC staff found the test plan acceptable.

The staff reviewed the power ascension testing performed as part of the original plan described in the DAEC Updated Final Safety Analysis Report (UFSAR) Table 14.2-3. The basis for testing was described in UFSAR Section 14.2.1.3. The startup testing requirements for the original DAEC test program were listed in Specification 22A2569, "General Electric Startup Test Specification." By letter dated August 9, 2004, the licensee provided a comparison of the EPU test program with the original plant startup test program, as described in DAEC UFSAR Section 14.2. Additionally, the licensee provided a matrix of these tests versus the thermal power levels at which testing was performed for Phase I and future phases of the EPU program. The NRC staff found that essentially, the test plans were similar in scope. However, the EPU plans do not include a full MSIV closure test (or main generator load reject test).

The NRC staff reviewed the following EPU test plan information provided by the licensee in order to verify that the initial EPU license amendment submittal, supplemental information provided in response to NRC staff RAIs, and applicable sections of TSs and the UFSAR addressed the specific criteria for an adequate EPU test program as described in SRP 14.2.1. Specifically, the following documents were reviewed during the NRC staff's evaluation:

- FSAR Section 14, "Initial Test Program" - Provided a detailed description of the licensee's initial startup test program's (1) administrative controls (2) scope of testing (systems tested), and (3) the overall test objectives, methods, and acceptance criteria.

- DAEC letter NG-05-0010, "Request for Segmented Review of License Amendment Request (TSCR-056)," dated January 7, 2005 - Provided a description of the revised request of the proposed change to the operating license, which would eliminate the MSIV closure test as part of the EPU.

- DAEC letter NG-04-011, "License Amendment Request (TSCR-056): Elimination of License Condition 2.C.(2)(b) for Performance of Large Transient Tests for Extended Power Uprate," dated February 27, 2004 - Provided a description of the proposed change, the supporting technical analysis, and evaluation of the No Significant Hazards Consideration for removing the license condition to perform large transient testing as part of the EPU.

- DAEC letter NG-04-0478, "Response to Request for Additional Information Regarding License Amendment Request (TSCR-056): Elimination of License Condition 2.C.(2)(b) for Performance of Large Transient Tests for Extended Power Uprate," dated August 9, 2004 - Provided responses to NRC staff questions for (1) a comparison of the EPU test program to the initial plant test program, (2) modifications and the associated post-modification tests (PMTs) that were performed and are planned for the EPU, and (3) the licensee's response on how SRP 14.2.1 was addressed.

- DAEC letter NG-01-764, "Response to Request for Additional Information (RAI) to Technical Specification Change Request TSCR-042 - Extended Power Uprate," dated June 11, 2001 - Provided licensee responses to RAIs on (1) proposed implementation of the power uprate phases, (2) types of high power startup tests performed, (3) recent transient events that could be an indicator of plant response to the EPU, and (4) post-scram evaluation of applicable transient events.

- DAEC letter NG-01-1198, "Final Typed Pages for Technical Specification Change Request TSCR-042 - Extended Power Uprate," dated October 17, 2001 - Provided inclusion of the commitment to perform certain transient testing during power ascension to the new licensed power level.

- DAEC letter NG-02-0187, "Startup Test Report for Extended Power Uprate - Phase 1," dated March 4, 2002 - Provided a summary of the startup testing performed at DAEC following implementation of the first phase of the EPU, which increased thermal power 8 percent from 1658 MWt (CRTP) to 1790 MWt (Phase I).

- "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 243 to Facility Operating License No. DPR-49 Nuclear Management Company, LLC Duane Arnold Energy Center Docket No. 50-331," dated November 6, 2001 - Provided an NRC safety evaluation of the licensee's proposed amendment request to allow an increase of the authorized operating power level from 1658 MWt (CRTP) to 1912 MWt (Phase III). The change represented an increase of 15.3 percent power above the current rated thermal power and therefore, was considered an EPU.

As part of this SE, the NRC staff reviewed the previous staff assessment of the EPU test program done for Amendment No. 243. Amendment No. 243 authorized operation up to 1912 MWt. Actual implementation of the EPU is being conducted in phases that support the licensee's modification schedule. Refer to the table in Section 1 of this SE for the power levels associated with the EPU phases.

As part of the licensee's review of the original test program, the following additional tests were evaluated for applicability to the EPU and added.

- Steady-State Data Collection: Key nuclear steam supply system and balance of plant parameters were recorded to ensure proper plant equipment performance.

- Power Conversion System Piping Vibration Monitoring: Main steam and feedwater (FW) piping was instrumented and monitored for unacceptable flow-induced vibrations.

- Turbine Combined Intermediate Valve (CIV) and Turbine Control Valve (TCV) Surveillance Testing: Testing similar to original testing for the turbine stop valve was conducted on the CIVs and TCVs. The purpose of the testing was to establish the proper level for conducting on-line surveillance testing of the CIVs and TCVs.

- General Service Water (GSW) Heat Exchanger Performance Monitoring: GSW piping size was increased for the EPU to provide additional cooling to key components. This monitoring program will confirm adequate design cooling.

Phase I Test Program

During performance of the Phase I test program, some acceptance criteria needed to be modified, as the original FSAR startup testing requirements were no longer applicable to the existing plant configuration. A problem in the FW level control system was discovered that required maintenance and re-performance of those tests at 1658 MWt. Also, based upon review of test data at lower power levels, the test matrix at high power was simplified and some tests were not performed, as they would not have provided useful data.

The completed testing at the Phase I target power level of 1790 MWt demonstrated stable plant operation. Changes in plant chemistry and radiological conditions were minor, vibration monitoring of main steam and FW piping was normal, and no plant equipment anomalies were noted.

The NRC staff found that all tests described in the initial startup test program were addressed in the description of the Phase I EPU test program. The NRC resident staff observed portions of the Phase I testing. No significant deficiencies were noted.

Phase II Test Program

The NRC staff reviewed the proposed testing for Phase II, which will increase power to approximately 1840 MWt. Specifically, the NRC staff reviewed the changes to the test program for Phase II that differ from the NRC staff review performed for Amendment No. 243. The licensee is herein proposing to eliminate the following test discussed below:

- Test No. 25b, MSIVs - Full MSIV Closure Test: This test was not required as part of EPU Phase I testing, as the required power level per the license condition is 1823.8 MWt (ELTR-1 power level for the MSIV closure test), which was not reached in Phase I. This test is currently required to be performed as part of Phase II testing. However, the purpose of this license amendment request is to not perform this test as part of EPU testing.

3.1.3 NRC Staff Conclusions Related to SRP 14.2.1 Section III.A.

The NRC staff concludes, through comparison of the documents referenced above, a review of test results from Phase I referenced in the FSAR, and a review of the test commitments proposed for Phase II, that the proposed EPU test program adequately identified (1) all initial power ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level, and (2) differences between the proposed EPU power ascension test program and the portions of the initial test program.

3.2 SRP 14.2.1 Section III.B.- Post Modification Testing Requirements for SSCs Important to Safety Impacted by EPU-Related Plant Modifications

3.2.1 Evaluation Criteria of SRP 14.2.1 Section III.B

SRP 14.2.1 Section III.B., specifies the guidance and acceptance criteria which the licensee should use to assess the aggregate impact of the EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs. AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as loss of all offsite power, tripping of the main turbine generator set, and loss of power to all reactor coolant pumps. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria (1) the performance of the SSC is impacted by EPU-related modifications, (2) the SSC is used to mitigate an AOO described in the plant-specific design-basis, and (3) involves the integrated response of multiple SSCs. The following should be identified in the EPU test program as it pertains to the above paragraph:

- 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, reactor pressure, flow, etc.) resulting from operation at EPU conditions.

3.2.2 <u>NRC Staff Evaluation Using SRP 14.2.1 Section III.B</u>

The NRC staff reviewed the planned EPU modifications and their potential effect on SSCs as documented in the DAEC letter NG-04-0478. The PMTs listed in the attachment to that letter were the acceptance tests to demonstrate design function performance and integration with the existing plant. The NRC staff also reviewed the basis for the licensee's conclusions that the modifications did not change the design function of the SSCs or the methods of performing or controlling their functions. The following modifications and PMT descriptions were reviewed by the NRC staff.

The following modifications were completed in May 2001 for Phase I (operation to 1790 MWt):

- Changes to the main turbine included (1) the high pressure turbine was replaced, (2) turbine control valve operation was converted to partial arc admission, and adjustments made to the electro-hydraulic control (EHC) system.
- Changes to the main generator included (1) new hydrogen coolers with increased cooling capacity, and (2) new GSW piping of increased capacity to support the larger hydrogen coolers.
- Larger main transformer coolers were installed.
- New temperature sensors to monitor isophase buss temperature were installed.
- A capacitor bank was installed to increase plant volts-ampere reactive capability and enhance grid stability.
- Changes to the FW heaters included (1) adjustment to FW heater level control settings to new heat balance, (2) trim on FW heater level control valves to allow higher flow, and (3) installation of a bypass around FW heaters 5A/B to maintain extraction steam flow at pre-EPU values for heater tube vibration concerns.
- Tube stakes were installed on the high and low pressure condenser tubes for vibration dampening.
- Instrumentation upgrades included (1) re-calibration of the local power range monitors and average power range monitors to the new 100 percent power, (2) trip reference cards installed for the maximum extended load-line limit analysis (MELLLA) operating

domain on the power-to-flow map, (3) new main steamline high flow trip instruments installed and re-calibrated to new setpoint, (4) turbine first stage pressure (reactor protection system and end-of-cycle recirculation pump trip bypass) were re-calibrated to new setpoints, based upon operating characteristics of the new high pressure turbine, (4) revised alarm setpoint for the standby liquid control system tank volume alarm, (5) control room indications respanned to new ranges, and (6) the process computer re-programmed to new instrument ranges.

- Sensors and a data collection system were installed for the main steam and FW piping vibration monitoring system.

- The main steam reheater cross-around relief valve capacity was increased (phased upgrade - one valve planned for each outage over four refueling outages).

All of the Phase I modifications have been installed, tested (performance monitoring, calibrations and startup testing) and are currently in operation. The NRC resident staff observed several of the PMTs performed for the above modifications. Also, portions of the Phase I power ascension were also observed. In addition, during the ensuing plant operation since EPU implementation, several plant events have occurred, including manual scrams from intermediate power levels, as well as a dual main recirculation pump runback event. In none of these actual events has the plant's dynamic response been abnormal. The NRC staff found the PMTs and subsequent observed equipment performance acceptable for the modifications performed in Phase I.

The following modifications are scheduled to be completed in the spring of 2005 for Phase II (operation to approximately 1840 MWt):

- The condensate pumps and motors will be upgraded to allow higher flow rate and their electrical protective relay settings adjusted. The PMT will include (1) factory acceptance testing (full flow performance test with motor), (2) pump and motor vibration baseline measurements, and (3) performance monitoring.

- FW heater upgrades will continue with replacement of the 3A/B, 4A/B and 5A/B FW heaters. The PMT will include (1) factory acceptance testing (eddy-current testing and non-destructive examination of welds), (2) in-service leak testing, (3) thermal performance testing, and (4) FW heater level controller adjustments.

The Phase II modifications are primarily to address current FW and condensate system flow capacity limitations. The modifications will bring system capacity up to that needed to achieve a target power level of approximately 1840 MWt. Because modifications are focused on the FW and condensate system, testing will target this equipment, in addition to the general testing required during power ascension. These modifications will not significantly change the overall plant dynamic response to the anticipated initiating events described in the UFSAR. The NRC staff found the proposed PMTs acceptable for the modifications to be conducted in Phase II.

3.2.3 NRC Staff Conclusions Related to SRP 14.2.1 Section III.B

The NRC staff concludes, based on review of each planned modification, the associated PMT, and the basis for determining the appropriate test, that the EPU test program will adequately demonstrate the performance of SSCs important to safety; included in this analysis are 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.

The NRC staff concludes that the proposed test program adequately identified plant modifications and setpoint adjustments necessary to support operation at the uprated power level and changes in plant operating parameters (such as reactor coolant temperature, pressure, reactor pressure, flow, etc.) resulting from operation at EPU conditions. Additionally, the NRC staff determines there are no unacceptable system interactions because of modifications to the plant.

3.3 SRP 14.2.1 Section III.C - Justification for Elimination of EPU Power Ascension Tests

3.3.1 Evaluation Criteria Using SRP 14.2.1 Section III.C

SRP 14.2.1 Section III.C., specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power ascension testing that should be considered for inclusion in the EPU test program pursuant to the review criteria of Sections 1 and 2 above. 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 anticipated operational occurrences, and
- guidance contained in vendor topical reports
- risk implications.

3.3.2 NRC Staff Evaluation Using SRP 14.2.1 Section III.C

The NRC staff focused the review on information regarding the following exception to original startup testing contained in the licensee RAI response letters NG-04-0478 and NG-01-0764.

- Test No. 25b, MSIVs - Full MSIV Closure Test: This test was not required as part of EPU Phase I testing, as the required power level per the license condition is 1823.8 MWt (ELTR-1 power level for MSIV closure test), which was not reached in Phase I. As part of the license condition, this test is currently required to be performed as part of Phase II testing. However, the purpose of this license amendment request is to not perform this test as part of EPU testing.

The NRC staff reviewed the licensee's response in NG-01-0764 regarding previous operating experience. The DAEC experienced unplanned events at approximately 1658 MWt (CRTP), which provided data for the MSIV closure test. In the first event, when the reactor was operating at approximately 1658 MWt, one MSIV unexpectedly closed due to a failed solenoid. Reactor pressure and reactor power increased and steam flow through the remaining three steamlines increased, until a full isolation of the main steamlines was initiated on high steam flow. No significant anomalies in the plant response were observed. In the second event, with the same reactor power, the main generator backup lockout differential current trip resulted in a turbine control valve fast closure event. The primary source signal for the reactor scram was the pressure switches on the EHC system that signal the fast closure of the turbine control valve. Again, no significant anomalies in the plant response were observed, with one exception. The FW controls allowed reactor level to increase to greater than the FW pump trip setpoint. While the Level 2 criterion (licensee established criterion for FW level control) was not met, the Level 1 criterion that the steamlines not flood was met. There is no safety consequence to the level 2 criterion not being met. Normal reactor water level control was subsequently established. The NRC resident staff observed the FW control troubleshooting. The licensee adequately resolved the FW control setpoint issue.

The licensee also cited Hatch Nuclear Plant, Unit 2, as an example of a similar plant which had an event subsequent to their EPU. Plant Hatch, Unit 2, is a boiling-water reactor (BWR) 4 with a Mark I containment of essentially the same design as the DAEC, including the key balance of plant area of turbine generator control logic. Hatch Nuclear Plant, Unit 2, had an unplanned event which resulted in a generator load reject from their full uprated power level. No anomalies were seen in the plant's response to this event. In addition, Plant Hatch, Unit 1, has experienced one turbine trip and one generator load reject event subsequent to its uprate. Again, the primary safety systems performed as expected. No new plant behaviors have been observed that would indicate that the analytical models being used are not capable of modeling plant behavior at the EPU conditions. A turbine trip and generator load reject event result in a pressurization transient similar to an MSIV closure event.

In response to the possible introduction of new thermal-hydraulic phenomena or identified system interactions, the licensee responded that none of the modifications implemented should have an impact in this area. The major EPU modification to the DAEC was to modify the main steam flow path from the reactor to the turbine generator to accommodate the higher steam flow due to the EPU. A new, more efficient high pressure turbine was installed and the TCVs were converted to partial arc mode. However, neither of these modifications introduced new thermal-hydraulic phenomena in the plant, nor do they introduce new or different system interactions that would warrant performing a pressurization transient test. The conversion to partial arc admission lessens the severity of a pressurization transient from operation in full arc admission. In addition, no instrument setpoints were modified that initiate equipment relied upon to mitigate this event.

Specifically, MSIV stroke times were not changed, nor were the opening settings of the safety/relief valves (S/RVs). No instrument setpoints were modified that initiate equipment relied upon to mitigate this event, such as the MSIV closure signal that initiates a reactor scram.

The MSIV closure is a pressurization transient caused by a fast shutoff of steam flow from the reactor vessel, from closure of the MSIVs. The transient severity is primarily determined by the initial operating pressure and rate of pressure increase (i.e., valve closure time). Rated reactor power (i.e., rated steam flow), has a noticeable, but secondary effect on the rate of pressure increase. NMC has implemented the DAEC EPU without a reactor pressure increase (commonly referred to as a constant pressure power uprate), or change in the shutoff valve stroke times. In addition, no modifications to the major SSCs used to mitigate this transient, such as the S/RVs or turbine bypass valves, have been made. Only rated steam flow has been affected by the EPU.

The NRC staff reviewed the licensee's response in NG-04-0111 to the introduction of new thermal-hydraulic phenomena or identified system interactions. The major EPU modification to the plant was to modify the main steam flow path from the reactor to the turbine generator to accommodate the higher steam flow due to the EPU. A new, more efficient high pressure turbine was installed and the turbine control valves were converted to partial arc mode. However, neither of these modifications introduced new thermal-hydraulic phenomena in the plant, nor do they introduce new or different system interactions that would warrant performing the MSIV closure test. As noted above, the conversion to partial arc admission lessens the severity of a pressurization transient from operation in full arc admission.

The NRC staff reviewed Section 3.7 of the Nuclear Reactor Regulation (NRR) SE for the DAEC EPU. Section 3.7 discussed the assessment of the effects of the EPU on the MSIV closure times. The original SE indicated that the NRC staff accepted the generic assessment on the MSIVs, which was documented in Section 4.7 of Supplement 1 to ELTR-2. The generic evaluation covered the effects of the power uprate changes on (1) the capability of the MSIVs to meet pressure boundary structural requirements, and (2) the safety function of the MSIVs.

The NRC staff accepted the generic assessment that the MSIV closure time can be maintained as analyzed and specified in the TSs. In addition, various surveillances require routine monitoring of MSIV closure time and leakage to ensure that the licensing basis for the MSIVs is preserved.

Based on the review of the evaluation and rationale, the NRC staff agreed with the conclusion that EPU operation would remain bounded by the generic evaluation in Section 4.7 of ELTR-2 and that the plant operation at the EPU level will not affect the ability of the MSIVs to perform their safety function.

The NRC staff reviewed the licensee's response in NG-04-0111 to facility conformance to limitations associated with analytical analysis methods. The licensee used General Electric's analytical model for analyzing transients (ODYN) and associated methods (GEMINI), which have been proven to acceptably predict plant behavior during a pressurization transient, including the DAEC, even at EPU conditions (e.g., Hatch). These methods are routinely used in the analysis of core reloads that form the basis for the core operating limit requirements. No new limitations on these methods have been imposed as a result of EPU implementation.

The NRC staff reviewed plant staff familiarization with facility operation and trial use of operating and emergency operating procedures. The NRC staff has previously reviewed and approved NMC's process for updating the plant operating procedures (normal and off-normal), training (including plant simulator), and human factors aspects of the DAEC's EPU implementation.

The NRC staff also noted that in describing and justifying test exceptions or deviations, the licensee adequately considered previous operating experience, the possible introduction of new thermal-hydraulic phenomena or system interactions, and margin reduction in safety analysis results for AOOs. Other factors used to determine the EPU test elimination included use of baseline operational data, updated computer modeling analyses, and industry experience.

Risk informed justifications for not performing a transient test was considered, as described in Section 10.4 of the SE for Amendment No. 243, but was not the sole factor in determining elimination of those tests. Previous operating experience, the initial startup test program report, computer model analyses and surveillance requirements were the major factors on those decisions.

3.3.3 NRC Staff Conclusions Related to SRP 14.2.1 Section III.C

The NRC staff concludes that, in justifying test eliminations or deviations, the licensee adequately addressed factors that included (1) previous operating experience, (2) introduction of new thermal-hydraulic phenomena or system interactions, and (3) staff familiarization with facility operation and use of operating and emergency operating procedures. The NRC staff determined that the licensee did not rely on analytical analysis as the sole basis for elimination of a power ascension test from the proposed EPU test program. Construction, installation and/or pre-operational testing for each modification will be performed in accordance with the plant design process procedures. The final acceptance tests will demonstrate that the modifications will perform their design function and integrate appropriately with the existing plant.

3.4 SRP 14.2.1 Section III.D - Adequacy of Proposed Testing Plans

3.4.1 Evaluation Criteria of SRP 14.2.1 Section III.D

SRP 14.2.1 Section III.D, specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety-related SSCs relied upon during operation shall be verified to be operable in accordance with existing and Quality Assurance Program requirements. The following should be identified in the EPU test program:

- the method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,
- appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flow rates, pressures, temperatures, response times of equipment, and the actual status of the plant,

- contingency plans if the predicted plant response is not obtained, and
- a test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

3.4.2 NRC Staff Evaluation Using SRP 14.2.1 Section III.D

The NRC staff reviewed Attachment 6 of NG-00-1900, which outlined the licensee's proposed EPU test plan. The NRC staff also reviewed the original NRR SEs conclusions on the adequacy of the startup test program. The NRC staff had concluded that the licensee's test plan followed the guidelines of ELTR-1 and satisfied the applicable requirements in Appendix B to 10 CFR Part 50.

The licensee will conduct limited startup testing at the time of implementation of the proposed EPU. The tests will be conducted in accordance with the guidelines of ELTR-1 to demonstrate the capability of plant systems to perform their design functions under uprated conditions.

The tests will be similar to some of the original startup tests described in Table 14.2-3 and Section 14.2.1.3 of the DAEC UFSAR. Testing will be conducted with established controls and procedures which have been revised to reflect the uprated conditions.

The tests will consist essentially of steady-state, baseline tests between 90 and 100 percent of the currently licensed power level. Several sets of data will be obtained between 100 and 115.3 percent current power with no greater than 5 percent power increments between data sets. A final set of data at the proposed EPU power level will also be obtained. The tests will be conducted in accordance with a site-specific test procedure, currently being developed by the licensee. The test procedure will be developed in accordance with written procedures as required by 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

The licensee indicated that the power increase test plan will have features as described in the Power Uprate Safety Analysis Report, Section 10.4, "Required Testing." Initial power ascension testing is outlined in Section 2.B.1 of this SE.

The guidelines in ELTR-1, Section 5.11.9, specify that pre-operational tests will be performed for systems or components which have revised performance requirements. These tests will occur during the ascension to EPU conditions. The performance tests and associated acceptance criteria are based on DAEC's original startup test specifications and previous General Electric BWR EPU test programs. The licensee's performance tests are discussed in Section 2.B.2 of this SE.

The NRC staff noted that the results from the uprate test program will be used to revise the operator training program to more accurately reflect the effects of the proposed EPU.

In addition, the plant staff, through classroom and/or simulator training, will be familiarized with the operation of the plant under EPU conditions. The training will include (1) plant modification and parameter value changes, (2) implementation/execution of normal, abnormal, and emergency operating procedures, and (3) accident mitigation strategies.

3.4.3 NRC Staff Conclusions Related to SRP 14.2.1 Section III.D

The NRC staff concludes that the proposed test plan will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design-basis for the facility. Additionally, the NRC staff concludes that the test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans exist if predicted plant response is not obtained.

3.5 Technical Evaluation Summary

The NRC staff has reviewed the EPU test program in accordance with SRP Section 14.2.1. This review included an evaluation of: (1) plans for the initial approach to the proposed Phase II thermal power level, including verification of adequate plant performance, (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed Phase II thermal power level, and (3) the test program's conformance with applicable regulations. For the reasons set forth above, the NRC staff concludes that the proposed EPU test program provides reasonable assurance that the plant will operate in accordance with design criteria and that SSCs affected by the EPU or modified to support the proposed power uprate will perform satisfactorily while in service. On this basis, the NRC staff finds that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Therefore, the NRC staff finds the licensee's proposed license amendment request to modify license condition 2.C.(2)(b) to eliminate the requirement to perform the full MSIV closure test from the EPU test program acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Iowa State official was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATIONS

The amendment changes a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding published April 13, 2004, (69 FR 19572). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: P. Prescott
Date: March 17, 2005

GE Energy, Nuclear
3901 Castle Hayne Rd
Wilmington, NC 28401

December 2, 2005
GE-VYNPS-AEP-415
DRF 0000-0007-5271

Action Requested by: NA
Response to: N/A
Project Deliverable: NA

GE Company Proprietary – This Letter is non-proprietary upon removal of Attachments

cc: G. Paptzun
B. Hobbs (ENOI)

To: Craig Nichols (ENOI)

From: Michael Dick

Author: Michael Dick

Subject: Information Copies of KKL (Leibstadt) Large Transient Test Comparison Reports

References:
1. Entergy Nuclear Operations Inc., Vermont Yankee Nuclear Power Station, AEP, GE Proposal No. 208-1JX8XA-HB1, Revision 5, dated November 13, 2002.
2. Entergy Nuclear Operations, Inc. Contract Order No. VY015144 (Asset Enhancement Program)

Attached to this letter please find information copies of the following large transient test comparison reports that were performed in support of the KKL (Leibstadt) extended power uprate project.

1. GENE-A13-00400-05, "Engineering Evaluation of KKL Load Rejection Test 100% Power (3138 MWt) 13 September 1996"
2. GENE-A13-00413-04-01, "Engineering Evaluation of KKL Turbine Trip Test 109% Power (3420 MWt) 11 September 1999"
3. GENE-0000-0003-1181-01, "Engineering Evaluation of KKL Turbine Trip Test 112% Power (3515 MWt) 07 September 2001"

These reports show comparisons of transient predictions using the GE ODYN code versus actual KKL test data. These reports are considered GE proprietary in their entirety and may not be released to any third party unless a proprietary information agreement between GE and the third party is in place.

As a point of clarification, the KKL original licensed thermal power (OLTP) is 3012 MWt. KKL performed a stretch power uprate to 104.2% OLTP (3138 MWt) after original plant licensing. KKL referenced all of the extended power uprate evaluations as a percentage of the stretch power uprate level. Therefore, the 112% power level (3515 MWt) is actually 116.7% of OLTP.

A signed copy of this letter is included in DRF 0000-0007-5271. Supporting technical information and evidence of verification for the Attachment 1 are contained in DRF 0000-0039-3917.

If you have any questions in this matter, please contact me.

MJD
Attachments:

1. GENE-A13-00400-05, "Engineering Evaluation of KKL Load Rejection Test 100% Power (3138 MWt) 13 September 1996" GE Proprietary Information
2. GENE-A13-00413-04-01, "Engineering Evaluation of KKL Turbine Trip Test 109% Power (3420 MWt) 11 September 1999" GE Proprietary Information
3. GENE-0000-0003-1181-01, "Engineering Evaluation of KKL Turbine Trip Test 112% Power (3515 MWt) 07 September 2001" GE Proprietary Information

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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 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

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 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 5 0 0 0
0 3	1 3	9 1	9 1	- 0 0 5 -	0 0	0 4	1 2	9 1		0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10CFR §: ✓ ONE OR MORE (11)

OPERATING MODE (9): N			
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 6 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.

NRC Form 366A (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 (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 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 subsequert to the turbine trip were in response to the characteristic drop in Reactor water level f'om 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

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 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.

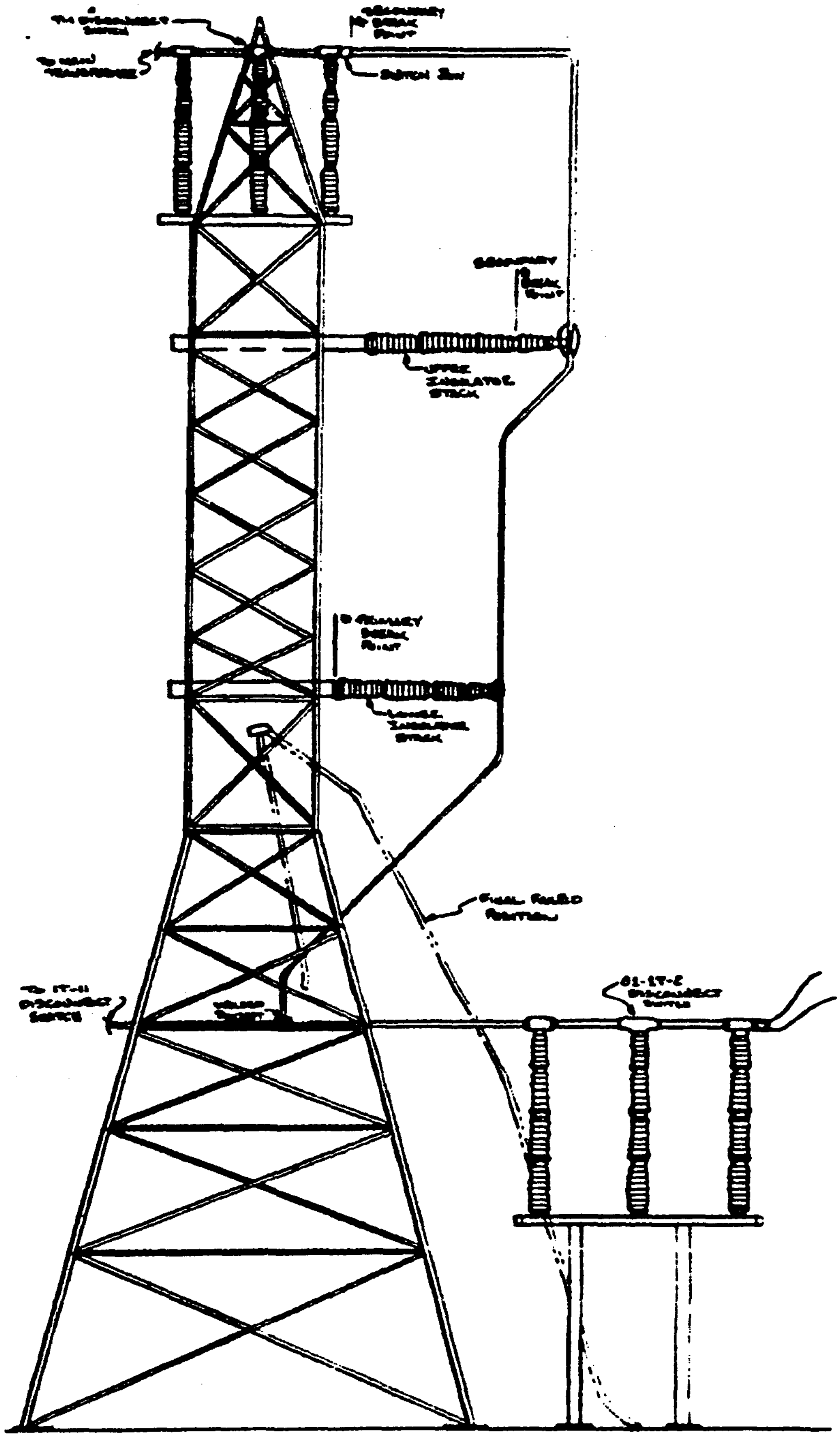
2. The failed insulator has been returned to the manufacturer for analysis and recommendations.

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.



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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 05/22/91. 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

PDR ADOCK 05000271
S PDR

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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 4	2 3	9 1	9 1	- 0 0 9 -	0 0	0 5	2 3	9 1		0 5 0 0 0
										0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10CFR §: ✓ ONE OR MORE (11)

OPERATING MODE (9): N	[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
POWER LEVEL (10): 1 0 0	[ ] 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)		EXPECTED SUBMISSION DATE (15)	MO	DA	YR
[X] YES (If yes, complete EXPECTED SUBMISSION DATE)	[ ] NO		0 8	3 0	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.

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89)

APPROVED OMS NO.3150-0104
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LICENSEE EVENT REPORT (LER)
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TEXT (If more space is required, use additional NRC Form 366A) (17)

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.

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LICENSEE EVENT REPORT (LER)
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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 inability 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

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

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

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

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION
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LICENSEE EVENT REPORT (LER)
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TEXT (If more space is required, use additional NRC Form 366A) (17)

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

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.

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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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)

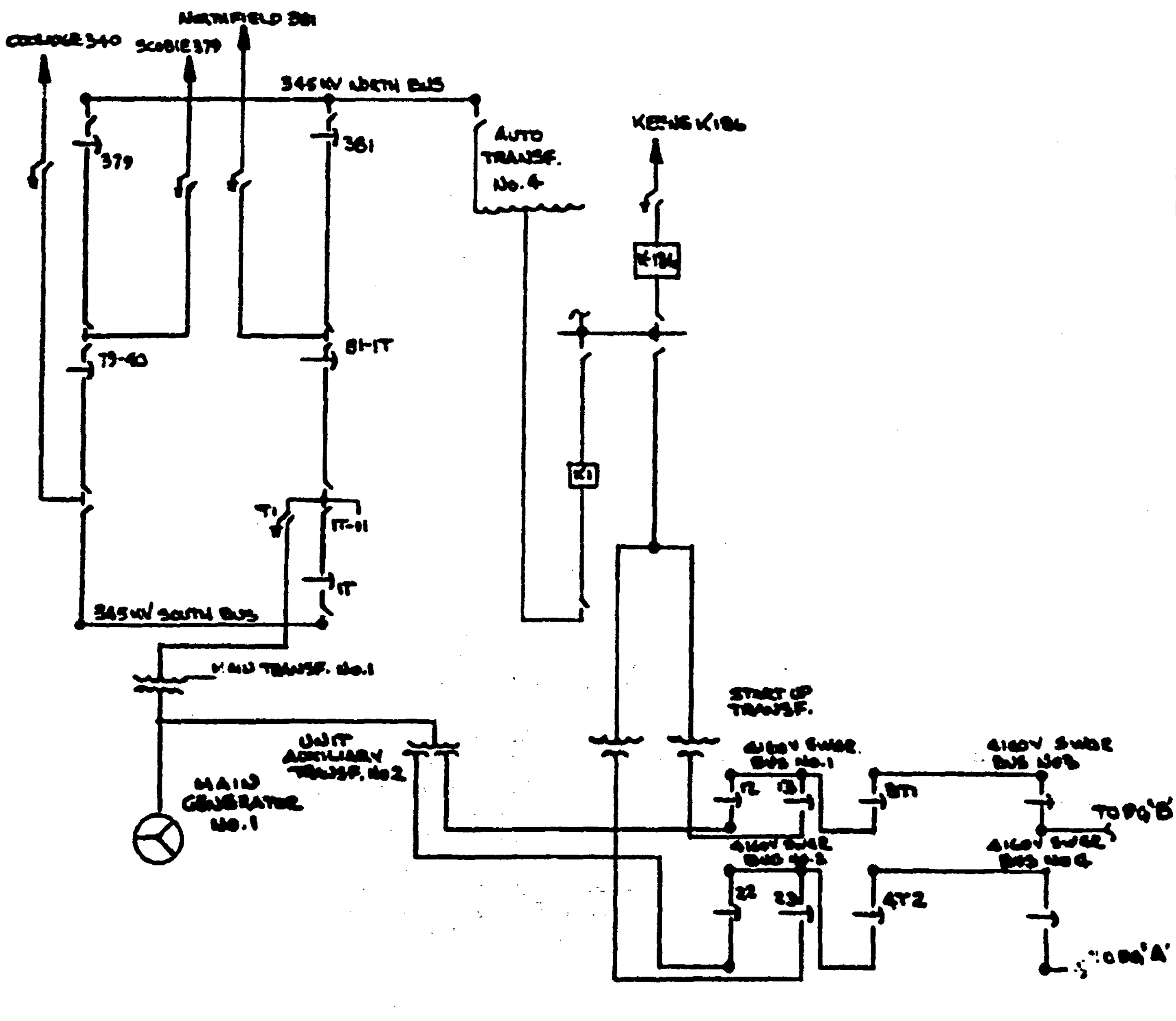
APPROVED OMS NO.3150-0104
EXPIRES 4/30/92

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 (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

UTILITY NAME (1)	DOCKET NO. (2)	LER NUMBER (6)					PAGE (3)		
		YEAR		SEQ. #		REV#			
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

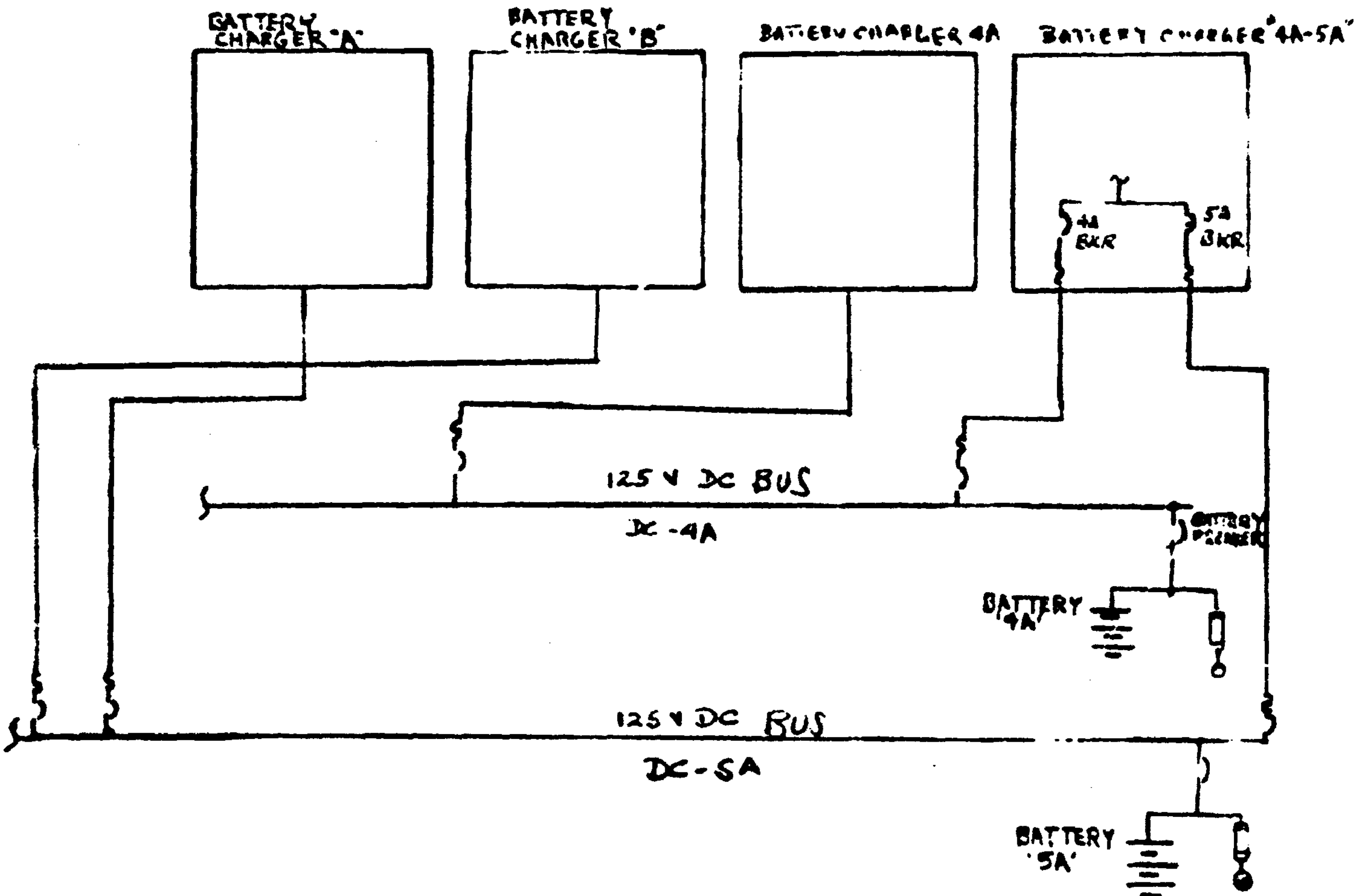
NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION
(6-89)

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.

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

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

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 N R C	G 0 8 0	N					

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15) MO DAY YR

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

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

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

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 3 OF 0 4

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.

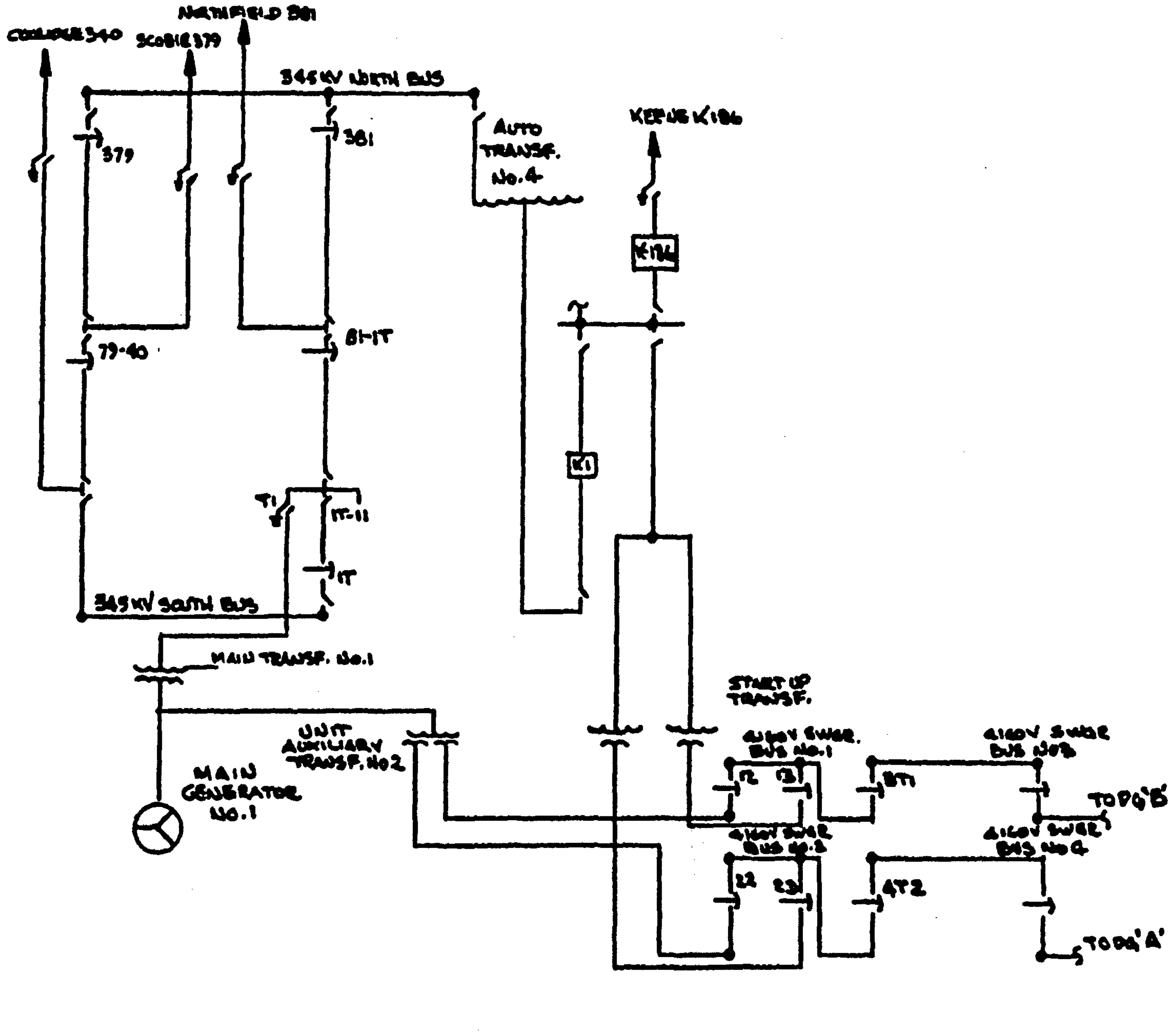
ATTACHMENTS

SKETCH: Switchyard Distribution

NRC Form 366A 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	07

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



SWITCHYARD DISTRIBUTION

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
Vermont Yankee
185 Old Ferry Rd.
P.O. Box 500
Brattleboro, VT 05302
Tel 802-257-5271

August 16, 2004
BVY 04-080

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 2004-003-00

As defined by 10CFR50.73, we are reporting the attached Reportable Occurrence LER 2004-003-00. No Regulatory Commitments have been generated as a result of this event.

Sincerely,

Entergy Nuclear Operations, Inc.
Vermont Yankee

Kevin Bronson

Kevin Bronson
General Manager

cc: USNRC Region I Administrator
USNRC Resident Inspector - VYNPS
USNRC Project Manager - VYNPS
Vermont Department of Public Service

IE22

LICENSEE EVENT REPORT (LER)

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

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
VERMONT YANKEE NUCLEAR POWER STATION (VY)	05000271	1 of 4

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	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME N/A	DOCKET NUMBER 05000 -
06	18	2004	2004 -	003	- 00	08	16	2004	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)(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)
Kevin Bronson, General Manager	(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 EXPECTED SUBMISSION DATE)	[X] NO		N/A	N/A	N/A

16. 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. Offsite power sources 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 extinguished the oil fire 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" iso-phase bus contributing to the failure of the "A" phase surge arrester. The root causes of the event were determined to be inadequate preventative maintenance on portions of the iso-phase bus and failure to monitor age related degradation on the surge arresters. There was no release of radioactivity or personnel injury during this event.

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
VERMONT YANKEE NUCLEAR POWER STATION (VY)	05000271	2004 -	003 -	00	2 OF 4

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 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 completely extinguished at approximately 0717and re-flash watches were established. Offsite power sources 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 10 CFR 50.72(b)(2)(iv)(B). At 1245, the Unusual Event was terminated.

The isophase bus flexible connector 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 suppressors were GE Alugard Station Arrestors, Model Number 9L11LAB, installed as original plant equipment. All of the surge suppressors were replaced.

CAUSES:

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 (EIIS=FCON) that allows the iso-phase bus to thermally expand and contract. The grounds raised the voltage on the "A" iso-phase bus, contributing to the failure of the "A" phase surge arrester. The root causes of the event were determined to be inadequate preventative maintenance for cleaning and inspections during outages and failure to monitor age related degradation.

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 or the presence of loose/foreign material with the potential to ground the bus. The need for

1. FACILITY NAME	2. DOCKET	6. LER NUMBER			3. PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
VERMONT YANKEE NUCLEAR POWER STATION (VY)	05000271	2004 --	003 --	00	3 OF 4

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

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" iso-phase bus and not performing preventative maintenance necessary to monitor age related degradation of the "A" surge arrester. Industry experience has revealed that surge arrestors 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.

A contributing cause to both of the conditions previously described was identified by the investigation team as a failure to effectively use industry OE to prevent similar events from occurring at VY. 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.

ASSESSMENT OF SAFETY CONSEQUENCES:

All safety systems and fire suppression systems responded as designed. The reactor was shutdown without incident. Offsite power sources and station emergency power sources were available at all times throughout the event. Emergency reponse personnel acted promptly to prevent the fire from significantly damaging or breeching 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 extiguished at 0717.
3. Completed the initial notification to the States of Vermont, New Hampshire and Massachusetts at 0721.
4. Notifed 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.

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

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 isophase bus duct system was monitored after assembly with the fans running to ensure that vibration levels are 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.

Long Term:

1. Include the 22kV surge arresters and capacitors in the preventative maintenance program and define periodic testing requirements.
2. Revise the 22kV isophase bus preventative maintenance program and periodic inspection requirements as necessary to improve performance and to prevent recurrence of this event.
3. Complete the testing of selected components involved in the event to validate the initial conclusions of the root cause investigation team, and revise the root cause analysis report if needed.

ADDITIONAL INFORMATION:

No similar events with a related cause have occurred at Vermont Yankee.

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

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

WFMaguire

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

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.