RAS 12303

Entergy

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U.S. NUCLEAR REGULATORY COMMISSION
In the Matter of Entergy Nuclear Vermont Yankee L.L.C.
Docket No. 50-271 Official Exhibit No. Staff 11
OFFERED by: Applicant/Licensee Intervenor ______
NRC Staff Other ______
IDENTIFIED on 9/13/06 Witness/Panel Ennis et al.
Action Taken: ADMITTED REJECTED WITHDRAWN
Reporter/Clerk UAC

August 1, 2005

Docket No. 50-271
BVY 05-072
TAC No. MC0761

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

DOCKET NUMBER
PROD. & UTIL. FAC. 50-271-OLA

Subject: **Vermont Yankee Nuclear Power Station**
Technical Specification Proposed Change No. 263 – Supplement No. 30
Extended Power Uprate – Response to Request for Additional Information

References:

1) Entergy letter to U.S. Nuclear Regulatory Commission, "Vermont Yankee Nuclear Power Station, License No. DPR-28 (Docket No. 50-271), Technical Specification Proposed Change No. 263, Extended Power Uprate," BVY 03-80, September 10, 2003

2) Entergy letter to U.S. Nuclear Regulatory Commission, "Vermont Yankee Nuclear Power Station, License No. DPR-28 (Docket No. 50-271), Technical Specification Proposed Change No. 263, Supplement No. 24 – Response to Request for Additional Information," BVY 05-024, March 10, 2005

3) U.S. Nuclear Regulatory Commission (Richard B. Ennis) letter to Entergy Nuclear Operations, Inc. (Michael Kansler), "Request for Additional Information – Extended Power Uprate, Vermont Yankee Nuclear Power Station (TAC No. MC0761)," July 27, 2005

This letter provides additional information regarding the application by Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy) for a license amendment (Reference 1) to increase the maximum authorized power level of the Vermont Yankee Nuclear Power Station (VYNPS) from 1593 megawatts thermal (MWt) to 1912 MWt.

The major aspects of this submittal are:

1) An update to Entergy's response to request for additional information (RAI) item SRXB-A-6 regarding certain analytical methodologies of General Electric (GE) that are used for the design and evaluation of VYNPS' fuel. The prior response to SRXB-A-6 was provided with Entergy's letter of March 10, 2005 (Reference 2) and is being superseded by this submittal.

A001

Template = SECY-027

SECY-02

2) An executive overview summarizing Entergy's understanding of the key issues remaining to provide reasonable assurance of steam dryer integrity at EPU conditions and also summarizing the framework for Entergy's response to those issues.

3) Responses to a significant number of those RAIs requested by NRC letter of July 27, 2005 (Reference 3). The remaining RAIs that pertain to the steam dryer and piping/nozzle stress evaluations are not included, but will be transmitted as a separate submittal by August 4, 2005.

GE Analytical Methods

In its letter of March 10, 2005, Entergy had proposed in its response to RAI SRXB-A-6 a means of addressing the NRC staff's questions regarding GE methods. The response was consistent with the Methods Interim Process proposed by GE in its letter of March 25, 2005 (MFN 05-005). Although Entergy remains confident that the concepts originally advanced in the response to RAI SRXB-A-6 are valid, an alternate, VYNPS-specific approach is provided by this letter. Entergy is revising and superseding the prior response to SRXB-A-6 with this submittal.

The alternate approach, discussed in the revised response to RAI SRXB-A-6 (Attachment 1), considers those core operating parameters and associated limits that could be impacted if all the uncertainties in methodology postulated by the staff were present during EPU operation, and then evaluating what, if any, operating restrictions should be imposed to compensate for this theoretical condition by providing additional safety margins to the affected limits. Using this approach Entergy has determined that a change of 0.02 to the safety limit minimum critical power ratio (SLMCPR) provides sufficient additional conservatism and adequate margin to address the postulated uncertainties in GE's methodology. Entergy is therefore proposing a license condition for EPU operation that imposes this additional 0.02 SLMCPR restriction until such time that the generic issues associated with GE analytical methods are adequately resolved with respect to VYNPS.

The alternate approach also describes Entergy's basis for confirming the adequacy of existing margin to accommodate the postulated uncertainties and assessing their impact on each of the remaining affected core operating parameters and associated limits. In addition, actual VYNPS operational experience with regard to core thermal limits is provided in the revised response to RAI SRXB-A-6.

Steam Dryer Analyses

Attachment 3 provides an overview of Entergy's understanding of the fundamental issues left to be resolved in order to provide reasonable assurance that steam dryer integrity will be maintained at EPU conditions. These issues are drawn from 129 individual questions posed by the NRC staff. Attachment 3 provides a restatement of

Entergy's overall approach to the steam dryer integrity issue and the framework of Entergy's strategy in addressing the remaining fundamental issues so that the answers to individual questions can be reviewed in that context. Attachment 5 provides responses to questions associated with computational fluid dynamics and steam dryer loads at EPU conditions. The remainder of the steam dryer-related RAIs are in review and are expected to be submitted by August 4, 2005.

Response to Requests for Additional Information

Attachments 4, 5, 7, 8, and 9 respond to individual RAIs, according to NRC review branch. Of the 200 individual RAIs requested by the NRC in Reference 3, 107 which pertain primarily to uncertainties in the acoustic circuit model, Scale Model Test benchmark adequacy, and applicability of the insights gained from the Quad Cities 2 instrumented dryer tests will be addressed in a future submittal, expected to be provided by August 4, 2005.

The revised response to RAI SRXB-A-6, as well as other responses to Reactor Systems Branch RAIs, (Attachments 1 and 9) contain Proprietary Information as defined by 10CFR2.390 and should be handled in accordance with provisions of that regulation. Attachments 1 and 9 are considered to be Proprietary Information in their entirety. Attachments 2 and 10 are non-proprietary versions of Attachments 1 and 9, respectively. Affidavits supporting the proprietary nature of the documents are provided as Attachment 6 (for Attachment 1), and as Attachment 12 (two affidavits for Attachment 9). "Exhibits," which provide supporting information to certain RAI responses are included in Attachment 11.

This submittal provides a substantial portion of the information needed to support the preparation of the NRC's safety evaluation report for EPU and is therefore being submitted in advance of the responses to the remaining questions. In compiling and analyzing the information for this submittal, Entergy remains convinced that the VYNPS can be safely operated at up to 120% CLTP. It is our understanding that an audit of the underlying details supporting elements of this submittal will be conducted on or about August 22, 2005. Entergy anticipates that the nature of the audit will be confirmatory and respectfully requests that additional requests for information, if any, be communicated as soon as practical.

The following attachments are included in this submittal:

Attachment	Title
1	Revised Response to RAI SRXB-A-6 (proprietary version)
2	Revised Response to RAI SRXB-A-6 (non-proprietary version)
3	Overview of Steam Dryer Issues
4	Responses to RAIs EEIB-A-1 through EEIB-A-5 (no proprietary information)
5	Responses to RAIs EMEB-B-18 through EMEB-B-149, non-inclusive (non-proprietary version)
6	Affidavit for Attachment 1

7	Responses to RAIs SPSB-C-47 through SPSB-C-52 (no proprietary information)
8	Responses to RAIs SPLB-A-25 through SPLB-A-29 (no proprietary information)
9	Responses to RAIs SRXB-A-7 through SRXB-A-58 (proprietary version)
10	Responses to RAIs SRXB-A-7 through SRXB-A-58 (non-proprietary version)
11	RAI Response Exhibits (10)
12	Two affidavits for Attachment 9
13	New Regulatory Commitments (2)

There are two new regulatory commitments contained in this submittal that are incorporated into the responses to RAIs EEIB-B-1 and EEIB-B-5 regarding actions associated with the postulated station blackout event. They are summarized in Attachment 13.

This supplement to the license amendment request provides additional information to clarify Entergy's application for a license amendment and does not change the scope or conclusions in the original application, nor does it change Entergy's determination of no significant hazards consideration.

Entergy stands ready to support the NRC staff's review of this submittal and suggests meetings (or audits of design files) at your earliest convenience.

If you have any questions or require additional information, please contact Mr. James DeVincentis at (802) 258-4236.

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

Executed on August 02, 2005.

Sincerely,

Robert J. Wanczyk

Robert J. Wanczyk
Director, Nuclear Safety Assurance
Vermont Yankee Nuclear Power Station

Attachments (13)

cc: (see next page)

cc: Mr. Richard B. Ennis, Project Manager
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Attachment 8

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263 – Supplement No. 30

Extended Power Uprate

Response to Request for Additional Information

Plant Systems Branch

Total number of pages in Attachment 8 (excluding this cover sheet) is 12.

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING APPLICATION FOR EXTENDED POWER UPRATE LICENSE AMENDMENT VERMONT YANKEE NUCLEAR POWER STATION

PREFACE

This attachment provides responses to the NRC Plant Systems Branch's (SPLB) individual requests for additional information (RAIs) in NRC's letter dated July 27, 2005.[1] Upon receipt of the RAI, discussions were held with the NRC staff to further clarify the RAI. In certain instances the intent of certain individual RAIs may have been modified based on clarifications reached during these discussions. The information provided herein is consistent with those clarifications.

The individual RAIs are re-stated as provided in NRC's letter of July 27, 2005.

Plant Systems Branch (SPLB)
Balance of Plant Section (SPLB-A)

RAI SPLB-A-25

Section 6.3.1 of Attachment 6 of the application dated September 10, 2003, indicates that in the unlikely event of a complete loss of spent fuel pool (SFP) cooling capability, the SFP will reach the boiling temperature in six hours. This conclusion does not appear to be consistent with the information that is provided for the alternate cooling system (ACS) in Updated Final Safety Analysis Report (UFSAR) Section 10.8 which indicates that upon a loss of all SFP cooling, boiling will occur in two-to-three days. Please explain this apparent inconsistency.

Response to RAI SPLB-A-25

The apparent inconsistency is due to two different scenarios—one assumes a batch off-load, the other a full core off-load.

Section 10.8.4 of the current UFSAR indicates that upon a loss of all SFP cooling, boiling will occur in two-to-three days. Section 10.8.4 also indicates that this time is based on a fuel pool heat load of 7.8×10^6 BTU/hr. This heat load is based on a batch off-load.

The six hour time to boil value for extended power uprate (EPU) is based on a full core off-load. Following extended power uprate, the time to boil value for a batch off load is approximately two days.

[1] U.S. Nuclear Regulatory Commission (Richard B. Ennis) letter to Entergy Nuclear Operations, Inc. (Michael Kansler), "Request for Additional Information – Extended Power Uprate, Vermont Yankee Nuclear Power Station (TAC No. MC0761)," July 27, 2005

RAI SPLB-A-26

UFSAR Section 10.8 indicates that the deep basin has a water capacity of 1.48 million gallons and that a water inventory of 1.45 million gallons is sufficient to assure seven days worth of ACS cooling capability. Please explain in detail how this conclusion was reached for post-EPU operation, quantifying all water additions and losses that are assumed to occur over this seven-day period along with how these values were determined, and how much inventory is required at the end of seven days to satisfy pump net positive suction head (NPSH) requirements.

Response to RAI SPLB-A-26

Water losses are due to evaporation, drift and external factors (e.g., pipe drainage during ACS setup, silt buildup and collapse of non-seismic portions of cooling structure). No makeup to the cooling tower is assumed for the entire duration of the ACS event. For ACS mode design basis heat loads and meteorological conditions, total seven day losses due to evaporation and drift were calculated to be 1,040,000 gallons and 29,000 gallons, respectively. Total losses due to external factors were calculated to be 266,800 gallons. The cooling tower has a minimum capacity of 1,451,700 gallons. Therefore, remaining inventory at the end of seven days of ACS operation is 116,000 gallons, equating to an inventory margin of 8%.

To maintain positive margin on NPSH over the entire seven day ACS event, two of the four RHRSW pumps are removed from service after 48 hours. The resultant reduction in suction header friction losses compensates to some degree for the reduction in suction static head caused by evaporative losses. At the end of four pump operation at 48 hours, minimum basin level is calculated to be 10 ft. above the first stage impeller of the RHRSW pumps. For the maximum pump flowrate at this point (approximately 2,105 gpm), required NPSH is 19.4 ft., and available NPSH is calculated to be 26.1 ft., yielding a margin of 6.7 ft., or 34%. At the end of seven days of ACS operation with only two pumps in operation, minimum basin level is calculated to be 4.2 ft. above the first stage impeller of the RHRSW pumps. For the maximum pump flowrate at this point (approximately 2,144 gpm), required NPSH is 19.9 ft. and available NPSH is calculated to be 29.9 ft., providing a margin of 10 ft., or 50%.

RAI SPLB-A-27

The response to RAI SPLB-A-17 in Supplement No. 28 indicates that there is sufficient margin between the minimum transient reactor feedwater pump (RFP) suction pressure and the current RFP suction pressure trip setpoint to ensure RFP operation during normal operation and the loss of one condensate pump transient. This does not appear to be consistent with the information provided in the RAI response that indicates that the condensate pumps only have a 7% flow margin to pump runout conditions, which would suggest that two condensate pumps operating are not sufficient to ensure RFP operation following the loss of one condensate pump. Please explain the basis for concluding that continued RFP operation is assured following the loss of one condensate pump.

Response to RAI SPLB-A-27

For clarification, the response to RAI SPLB-A-17 in Supplement No. 28 relates to the impact on current equipment and system margins due to EPU implementation.

The 7% condensate pump flow (CP) margin discussion applies to normal EPU operation with all three CPs operating. The 7% flow margin is determined by comparing total condensate system flow during normal EPU conditions and the maximum possible condensate system flow demand assuming minimum total condensate and feedwater system resistance. That is, at EPU, the CPs will be required to produce 7% more flow to sustain the maximum possible system flow. This is well within the capabilities of the CPs since the runout flow for the CPs is 7,450 gpm whereas the maximum required system runout flow per CP is 5,781 gpm.

The RFP suction pressure trip setpoint discussion relates to the basis for selection of the RFP suction pressure trip setpoint. This setpoint is based on assuring that, for normal and off-normal operation (including the trip of one condensate pump), sufficient pressure exists at the suction of the RFPs to provide more NPSH available than NPSH required by the pump to avoid potentially harmful pump suction cavitation.

The response to RAI SPLB-A-17 in Supplement No. 28 also described an automatic runback of the recirculation pumps that will be implemented for EPU. This feature is designed to ensure that upon a trip of a condensate pump or a feedwater pump, a recirculation pump runback will occur to quickly reduce reactor power and steam flow to values that allow the remaining operating pumps to support continued plant operation.

The loss of an operating CP at EPU conditions results in:

1. Reduced feedwater flow, which affects reactor water level. That is, with two operating CPs, following a loss of one of the three CPs, the condensate and feedwater system is incapable of supplying feedwater flow rates necessary for full power operation–even if the demineralizers are at the cleanest condition and the feedwater regulating valves are 100% open.

   Upon a loss of a CP, to maintain full power, each remaining CP would have to provide about 8,100 gpm. However, given the system hydraulic characteristics with the feedwater regulating valves 100% open, the maximum flow possible per CP is calculated to be 7,537 gpm following a loss of a CP. Thus, it is not possible to maintain full power following a loss of a CP.

   As indicated above, the reactor recirculation (RR) system runback feature is intended to quickly reduce reactor power and steam flow to values that allow the remaining operating pumps to support continued plant operation at a reduced power level.

2. The calculated RFP suction pressure following the trip of one CP at EPU is approximately 124 psig. This suction pressure is the minimum pressure predicted prior to the RR runback assuming the feedwater regulating valves are full open and maximum DP across the condensate demineralizers. The RFP low suction pressure trip setpoint is currently set to 98 psig, to avoid a RFP suction pressure trip following a CP trip. This setpoint will be retained for EPU conditions.

3. The remaining two operating CPs will continue to maintain sufficient NPSHA for the RFPs at the maximum resulting individual CP flow of 7,537 gpm. This maximum flow of 7,537 gpm would be available prior to the runback, assuming the feedwater regulating valves are full open and minimum DP across the condensate demineralizers.

   The resulting individual CP flow of 7,537 gpm is 87 gpm or approximately 1% more than the published characteristic curve maximum flow of 7,450 gpm (i.e., 7,537 – 7,450 = 87 gpm). Since the increased flowrate is practically insignificant, reasonable estimates of CP capabilities, TDH and NPSHR, can be obtained by extrapolating the pump characteristic curve to the slightly higher flowrate. From this extrapolation, it is estimated that at the resulting flow rate of 7,537 gpm, the CP NPSHA is about 10 feet above the estimated pump NPSHR indicating that more than sufficient NPSHA exists to prevent CP cavitation.

   Since the remaining two CPs continue to operate with more than sufficient NPSHA, the lowest calculated RFP suction pressure will be approximately 124 psig or well above the RFP suction trip setpoint of 98 psig.

RAI SPLB-A-28

EPU operation will result in a substantial reduction in the available condensate and feedwater system operating margin and plant modifications must now be credited for preventing challenges to reactor safety systems that would otherwise occur upon the loss of a RFP or a condensate pump. Because the plant response to loss of RFP and condensate pump events following EPU implementation is substantially different from the response at the current licensed power level, and the expected EPU response has not been confirmed by previous full power tests or plant transients, the NRC staff requires that the power ascension test program include sufficient testing at the 100% EPU power level to confirm that the plant will respond as expected following a) the loss of a RFP, and b) the loss of a condensate pump. Please provide a complete description of the full-power testing that will be completed in this regard for the staff's review and approval, and propose a license condition that will assure that the proposed testing will be completed as described and that the results are fully satisfactory as a prerequisite for continued operation at the EPU power level.

Response to RAI SPLB-A-28

This response is supported by the information previously provide in response to RAI SPLB-A-17, page 9 of 23, and RAI-SPLB-A-18, page 12 of 23, as Attachment 1 to Entergy letter BVY-05-046, dated April 22, 2005.

A modification to the condensate and feedwater system was installed at VYNPS to add a reactor recirculation (RR) pump runback as a trip avoidance feature to reduce the potential for a reactor low water level scram on the loss of either a feedwater or condensate pump at EPU conditions. Although not required to achieve full EPU operation, Entergy determined it is prudent to avoid this potential plant transient/trip in the very unlikely event that a condensate pump (CP) or reactor feedwater pump (RFP) trips at EPU operating conditions. A dynamic analysis of a single feedwater pump trip at EPU conditions indicates that an automatic reactor recirculation runback can reduce core flow and thermal power to within the capability of the running feedwater pumps and avoid a reduction in reactor water level to the scram setpoint.

VYNPS has been analyzed to respond to a reactor trip on low reactor water level at EPU conditions and maintains adequate margin to safety for this event. The RR pump runback feature is not a safety function because the reactor is designed to scram if operating limits are exceeded; it is rather an operational reliability issue because it is preferred that the loss of a condensate or feedwater pump not result in a scram.

The runback logic is enabled when reactor power exceeds the capability of two feedwater pumps, as measured by total steam flow (approximately 112% of CLTP). A runback is initiated when fewer than three feedwater pumps and three condensate pumps are running and total feedwater flow exceeds the capacity of two feedwater pumps. The automatic runback will rapidly reduce core flow to approximately 60% of rated EPU core flow.

A transient analysis performed by GE in support of VYNPS using an NRC approved code (ODYN) shows that even in a degraded condition:

> *"The results of the single feedwater pump trip evaluations show that even the cases with a very degraded response and 1-element feedwater control show the acceptability of the reactor recirculation run back. Reactor water level remains above the low reactor water scram setpoint and below the high reactor water level trip setpoint (Level 8) for all conditions."*

Thorough logic testing was performed as part of the modification, including using breaker trips to initiate the runback circuitry and monitoring RR pump controls. Based on the analysis of the plant response to the pump trip and the offline testing performed during post-modification testing, it has been determined that no functional test is warranted.

The EPU configuration differs from the current configuration which uses two RFPs with one RFP available as a standby pump. During steady state EPU operation, the three RFPs will operate at lower pump capacity (5,831 gpm) with less stress on pumps and motors than two RFPs operating at CLTP (6,965 gpm). This reduction in individual RFP flow increases the available margin from normal operating flows to runout for the individual pump. Each CP will be required to provide the increased flow associated with EPU operation with the same number of pumps (i.e., three) currently being used. The CP flow margin between the EPU conditions and the runout with three RFPs and three CPs will be approximately 7% greater than the required EPU flow. Industry criteria typically recommend a 5% margin. As such, the available margin exceeds that typically required by industry.

The operation of the feedwater and condensate systems in terms of required response to initiating events does not fundamentally change at EPU. At CLTP the trip of a CP requires operator action to reduce RR flow/power level to a point supported by the remaining pumps. When one RFP is out of service operations must also reduce flow/power rapidly to avoid the low level trip. In fact, without the modification the likelihood today is that the trip of a RFP without a standby pump in autostart will likely result in a reactor trip. The RFPs and CPs at VYNPS have a long history of reliable operation. No pump trips at power have occurred in at least the last ten years of power operation.

Based on discussions with others in the nuclear industry, no other uprated BWR needed to perform an integrated test to confirm the RR runback performed as designed. Additionally, for BWRs that installed the runback feature as part of original plant design, only one BWR plant could be identified as having performed the test.

This modification was installed for both operational support and economic reasons. The economic reasons include keeping the plant on line and minimize operator response to a transient involving the loss of a single RFP or CP at EPU conditions. The operational support reasons are to avoid an unnecessary low level scram during EPU conditions due to a loss of a RFP or CP at EPU conditions.

NRC's Standard Review Plan (SRP) 14.2.1, Section III.B.1 states: "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 <u>safety impact</u> (emphasis added) 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 <u>functions important to safety</u> (emphasis added) 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 RR runback based on a RFP or CP trip or low feedwater pump suction pressure does not meet any of the criteria per Attachment 2, "Transient Testing Applicable to Extended Power Uprates." However, additional insight is gained by review of the exception criteria provided in SRP 14.2.1 Section III.C.

Addressing SRP Section III.C:

a. Previous operating experience:

   Entergy is unaware of any VYNPS or industry EPU operating experience that supports performance of this test. The operational history of VYNPS and the very limited industry experience with RFP and CP trips at power supports that there is little benefit in injecting this transient.

b. Introduction of new thermal hydraulic phenomena or identified system interactions:

   There are no new thermal hydraulic phenomena (reducing RR flow based on a pump trip is not a new thermal hydraulic phenomena) or system interactions that may be introduced as a result of the RR runback. Feedwater flow changes due to plant events (e.g., pump trip, valve malfunction) result in pre-analyzed transients (low water level reactor trip, high level turbine trip).

c. Facility conformance to limitations associated with analytical analysis methods:

The ODYN analysis cannot provide 100% confidence that a scram is avoided. It is dependent on the actual runback rate and various systems' performance at the time of the postulated event. There may be certain operating conditions where the plant is more vulnerable to scram. The real margin to a scram will depend on the actual instrument setting and whatever instrument drift upwards may occur. This is acceptable as the impacted systems are not safety related and uncertainty in the analysis would not alter potential outcomes (no outcome different than analyzed events).

d. Plant staff familiarization with facility operation and trial use of operation and emergency operating procedures:

Plant operators have been trained on both the automatic plant response and any required operator actions in response to these events. This includes simulator exercises that include these events. No different types of operator actions are required.

e. Margin reduction in safety analysis results for anticipated operational occurrences:

There is no reduction in margin to safety in either installation of the modification performed or the lack of an online integrated test. The modification was installed to minimize operational transients and avoid a plant trip in response to the pump trip. Failure of the modification to initiate the runback, failure in the execution of the runback, or a plant response to the runback different than that modeled in the analysis will lead to a reactor low level trip or a high level turbine trip (analyzed events that have been experienced at VYNPS and elsewhere).

f. Guidance contained in vendor technical reports:

No guidance is contained in vendor technical reports related to performing integrated tests related to the RR runback.

g. Risk Implications:

VYNPS is not proposing a risk informed basis for not performing certain transient tests.

Conclusion

Entergy has instituted all of the necessary modifications and required post-modification testing at VYNPS to provide reasonable assurance that the feedwater and condensate system will remain highly reliable, and in the event of a pump trip, no new challenge to safety occurs. Therefore, Entergy believes that there is no need for a license condition, and no need to perform an integrated plant test to trip both a CP and separately a RFP at full EPU conditions to demonstrate the ability of the RR runback and feedwater low suction pressure modification to function as designed.

RAI SPLB-A-29

The licensee's response to RAI SPLB-A-20(a) in Supplement No. 28, is incomplete in that only the balance-of-plant (BOP) startup transient response criteria for the main steam isolation valve closure and generator load rejection transients were addressed. In accordance with the review criteria provided in NRC Review Standard RS-001 and draft Standard Review Plan (SRP) Section 14.2.1, the staff's request applies to the BOP transient response for all of the startup tests that are potentially impacted by the proposed EPU. Please provide the additional information that is needed in this regard.

Response to RAI SPLB-A-29

For all startup tests that are potentially impacted by the proposed EPU, GE Document No 22A2217, Revision 1, Vermont Yankee Startup Test Specification, dated January 5, 1973 was reviewed to determine if any of the original VYNPS balance of plant (BOP) startup testing transient response criteria are affected. The criteria section of this document specifies Level 1 and Level 2 criteria which are defined as follows:

Level 1:

These values of process variables assigned in the design of the plant and equipment are included in this category. If a Level 1 criterion is not satisfied, the plant will be placed in a hold condition which is satisfactory, until a resolution is made. Tests compatible with the hold condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 criterion are satisfied.

Level 2:

The limits considered in this category are associated with expectations in regard to the performance of the system. If a Level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be started.

Table SPLB-A-29-1 below lists the startup tests that are potentially impacted by the proposed EPU, and the Level 1 and Level 2 Acceptance Criteria per GE Document No 22A2217, Revision 1, Vermont Yankee Startup Test Specification, dated January 5, 1973.

Conclusion:

After reviewing the list below, for all of the startup tests that are potentially impacted by the proposed EPU, none of the original VYNPS balance of plant (BOP) startup testing transient response criteria are affected.

Table SPLB-A-29-1

Test #	Description	BOP Transient Response Acceptance Criteria Evaluation
1	Chemical and Radiochemical	Level 1: o Water quality must be known and must conform to water quality and fuel warranty specifications. o The activity of gaseous and liquid effluents must be know and must conform to license limitations. o Chemical factor defined in the Technical Specifications must be maintained within limits specified. Level 2: o None
2	Radiation Measurements	Level 1: o The radiation doses of plant origin and occupancy times shall be controlled consistent with the guidelines of the standards for protection against radiation 10CFR20. Level 2: o None

10	IRM Performance	Level 1: o None Level 2: o The IRM channels will be calibrated to read equal to or grater than the actual percent of reactor rated thermal power, and will overlap the SRM and APRM reading.
12	APRM Calibration	Level 1: o The APRM channels must be calibrated to read equal to or greater than the actual core thermal power. Level 2: o None
19	Core Performance	Level 1: o Reactor power, maximum fuel surface heat flux, and minimum critical heat flux ratio (MCHFR) must satisfy the following limits: o Maximum fuel rod surface heat flux shall not exceed 134 W/cm^2 (425,500 BTU/hr-ft^2). o Minimum CHF ratio shall not be less than 1.9 when evaluated at the operating power level. The basis for evaluation of MCHFR shall be "Design Basis for Critical Heat Flux Condition in BWRs" APED-5286, Sept. 1966. o Normal reactor power shall be limited to 1593 MWt for the steady state conditions. Level 2: o None

22	Pressure Regulator	Level 1: o The decay ratio must be less than 1.0 for each process variable that exhibits oscillatory response to pressure regulator changes. Level 2: o The decay ratio is expected to be less than or equal to 0.25 for each process variable that exhibits oscillator response to pressure regulator changes when the plant is operating above the lower limit setting of the Master Flow Controller. o During the simulated failure of the operating pressure regulator, the backup pressure regulator shall control the transient such that the reactor does not scram.
23	Feedwater Control System Testing	Level 1: o The decay ratio must be less than 1.0 for each process variable that exhibits oscillatory response to feedwater system changes. Level 2: o The decay ratio is expected to be less than or equal to 0.25 for each process variable that exhibits oscillator response to feedwater system changes when the plant is operating above the lower limit setting of the Master Flow Controller.

24	Turbine Valve Surveillance	Level 1: o The decay ratio must be less than 1.0 for each process variable that exhibits oscillatory response to bypass valve changes. Level 2: o The decay ratio is expected to be less than or equal to 0.25 for each process variable that exhibits oscillator response to bypass valve changes when the plant is operating above the lower limit setting of the Master Flow Controller. This transient is not expected to cause a scram.
25	Main Steam Isolation Valves	Level 1: o MSIV stroke time will be between 3 and 5 seconds. Reactor pressure shall be maintained below 1230 psig, the setpoint of the first safety valve, during the MSIV closure event. Level 2: o The maximum reactor pressure should be 35 psi below the first safety valve setpoint. This is a margin of safety for safety valve weeping.
100	Main Steam and Feedwater Piping Vibration	Not part of the original Startup Test Specification