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BVY 11-010

February 4, 2011

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

SUBJECT: License Renewal Application Supplemental Information
Vermont Yankee Nuclear Power Station
Docket No. 50-271
License No. DPR-28

REFERENCES: 1. Letter, Entergy to USNRC, "License Renewal Application," BVY 06-09, dated January 25, 2006

Dear Sir or Madam:

On January 25, 2006, Entergy Nuclear Operations, Inc. and Entergy Nuclear Vermont Yankee, LLC (Entergy) submitted the License Renewal Application (LRA) for the Vermont Yankee Nuclear Power Station (VYNPS) as indicated by Reference 1.

Attachment 1 of this letter provides supplemental information to the LRA to address questions discussed with the NRC staff on teleconferences held on January 6, 2011, January 26, 2011 and January 31, 2011.

Revised regulatory commitments are provided in Attachment 2.

Should you have any questions or require additional information concerning this submittal, please contact Mr. Robert Wanczyk at 802-451-3166.

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

Executed on February 4, 2011.

Sincerely,

[MJC/PLC]

Attachments: 1. License Renewal Application Supplemental Information
2. List of License Renewal Commitments

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Attachment 1

Vermont Yankee Nuclear Power Station
License No. DPR-28 (Docket No. 50-271)

License Renewal Application

Supplemental Information

Vermont Yankee Nuclear Power Station
License Renewal Application - Supplemental Information

Vermont Yankee Nuclear Power Station (VYNPS) provides the following supplemental information to address questions discussed with the NRC staff on teleconferences held on January 6, 2011, January 26, 2011 and January 31, 2011. The information covers the following areas:

1. Neutron-absorbing material
2. Buried piping
3. Non-EQ inaccessible medium-voltage cables
4. Protective coatings inside containment

Neutron-Absorbing Material

Background

VYNPS provided additional information related to the Neutron Absorber Monitoring Program in LRA supplemental information letters dated October 14, 2010 (BVY 10-052) and December 21, 2010 (BVY 10-058). In BVY 10-058, VYNPS provided LRA Section A.2.1.37 of Appendix A and B.1.31 of Appendix B to describe the aging management program for neutron-absorbing materials, specifically Boral, during the period of extended operation (PEO). Based on teleconferences held with NRC staff on January 6, 2011 and January 26, 2011, VYNPS is providing the following supplemental information in order to support the staff's evaluation of the program.

Discussion

VYNPS has nine racks installed in the spent fuel pool that were manufactured by Nuclear Energy Services (NES). There are two racks installed which were manufactured by Holtec. Each rack uses Boral as the neutron-absorbing material.

VYNPS intends to use coupon testing for the Boral material in the NES racks. Three coupon strings are installed in the NES racks, each holding three Boral coupons. If coupon testing is feasible, the coupons will be analyzed to measure B-10 areal density and geometric changes (i.e. blistering, pitting and bulging). An engineering evaluation will determine if the results of the NES coupon testing will be representative of the Boral in the Holtec racks.

In the event coupon testing is not feasible or will not be representative of spent fuel rack neutron-absorbing materials, VYNPS plans to employ the in-situ Boron-10 Areal Density Gauge for Evaluating Racks (BADGER) method to measure the Boron-10 areal density of the spent fuel racks. The BADGER method is a form of in-situ neutron attenuation testing. The BADGER method has not been demonstrated on Boral racks. In the event that the BADGER method is not found acceptable for use on Boral spent fuel racks, VYNPS will perform in-situ neutron attenuation blackness testing of a representative number of spent fuel rack locations to validate the minimum B-10 areal density assumptions used in the VYNPS spent fuel pool criticality analysis.

The primary parameter to be monitored during the PEO is B-10 areal density. The acceptance criteria will be the minimum B-10 areal density necessary to meet the assumptions in the spent fuel pool criticality analysis, which for VYNPS is 0.0270 g/cm^2. When analyzing coupons, a number of measurements will be made of the areal density of each coupon and then averaged, and any geometric or physical (blistering, pitting and bulging) changes will be identified, recorded and evaluated.

The blistering observed in 1996 was cosmetic in nature. Based on this operating experience, an increased frequency of coupon testing was not warranted by the blistering observed in 1996.

The first testing will be completed prior to the end of 2014 to confirm that the boron areal density of the Boral material will continue to meet the assumptions of the VYNPS spent fuel pool criticality analysis. Any degradation noted during testing or problems noted during spent fuel movement will be entered into the VYNPS corrective action program and evaluated. In accordance with the recommendations of NUREG-1801, the frequency of testing during the PEO will be at least once every ten years. The interval between tests will be shortened if the results of the VYNPS testing or testing of similar materials at other Entergy facilities or industry operating experience indicate that unacceptable degradation may occur prior to the next scheduled test.

The Seabrook Part 21 report of Boral coupon blistering was evaluated at VYNPS through the corrective action program. The evaluation determined that blistering may have a possible long term effect on spent fuel pool fuel handling or reactivity control, such that an investigation of the long-term effects of Boral blistering was warranted. In response to the evaluation, Entergy initiated a Boral monitoring program that used Indian Point Unit 3 (IP3) as the lead plant. The results from IP3 inspection and testing are used to determine if additional actions are necessary at other sites. Inspections at IP3 under this program have not detected significant degradation that impacted design requirements or warranted additional inspections at VYNPS. Degradation in future inspections at IP3 or other Entergy sites, if any, will be assessed through the corrective action program for the need to modify the VYNPS Neutron Absorber Monitoring Program.

The following describes the 10 elements of the VYNPS Neutron Absorber Monitoring Program.

NEUTRON ABSORBER MONITORING PROGRAM

Program Description

The Neutron Absorber Monitoring Program is a new program that manages loss of material and reduction of neutron absorption capacity of Boral neutron absorption panels in the spent fuel racks. The program will rely on periodic inspection, testing, monitoring and analysis of the criticality design to assure that the required five percent subcriticality margin is maintained during the period of extended operation.

The program will be initiated prior to the period of extended operation. The first testing will be completed by the end of 2014.

Evaluation and Technical Basis

1. ***Scope of Program*:** The AMP manages the effects of aging on Boral neutron-absorption panels used in spent fuel racks at VYNPS.

2. ***Preventive Actions*:** This AMP is a condition monitoring program, and therefore, there are no preventive actions.

3. ***Parameters Monitored/Inspected*:** The parameters monitored include the physical condition of the Boral neutron-absorption panels including geometric changes in the material (formation of blisters, pits, and bulges) as observed from coupons or in situ testing. The primary parameter to be monitored is B-10 areal density.

4. ***Detection of Aging Effects*:** The loss of material and the degradation of the Boral neutron absorption capacity will be determined through coupon or direct in-situ testing. VYNPS will use coupon testing if practical for the Boral material. VYNPS has three coupon strings, each holding three Boral coupons. The coupon testing will measure B-10 areal density and geometric changes (i.e. blistering, pitting and bulging). Any geometric or physical changes (blistering, pitting and bulging) will be identified, recorded and evaluated if coupon testing is performed.

VYNPS will employ the in-situ Boron-10 Areal Density Gauge for Evaluating Racks (BADGER) method on Boral spent fuel racks to measure Boron-10 areal density to either supplement or in lieu of coupon analysis in the event coupon analysis is unavailable or determined not representative of the rack configuration. The primary parameter to be monitored during the PEO is B-10 areal density. The frequency of the inspection and testing will be at least once every 10 years. The interval between tests will be shortened if the results of the VYNPS testing or testing of similar materials at other Entergy facilities indicate that unacceptable degradation may occur prior to the next scheduled test.

5. ***Monitoring and Trending*:** The measurements from periodic inspections and analysis will be compared to prior measurements and analysis for trend analysis. When analyzing coupons, a number of measurements are made of the areal density of each coupon and then averaged.

6. ***Acceptance Criteria*:** Testing will confirm that the Boral panels continue to meet the minimum B-10 areal density assumptions of the spent fuel pool criticality analysis. For VYNPS, the minimum B-10 areal density assumed is 0.0270 g/cm^2.

7. ***Corrective Actions*:** If a) the results from measurements and analysis indicate that the 5% sub-criticality margin cannot be maintained because of current or projected degradation of the neutron-absorbing material, b) degradation is noted during testing, or c) problems noted during spent fuel movement, the condition will be entered into the corrective action program. The requirements of 10 CFR Part 50, Appendix B, address corrective actions.

8. ***Confirmation Process*:** The requirements of 10 CFR Part 50, Appendix B, are acceptable to address the confirmation process.

9. ***Administrative Controls*:** The requirements of 10 CFR Part 50, Appendix B, are acceptable to address administrative controls.

10. ***Operating Experience*:** Some of the industry operating experience with neutron absorbing material is listed below.

1. Loss of material from the neutron absorbing material has been seen at many plants, including loss of aluminum, which was detected by monitoring the aluminum concentration in the spent fuel pool. One instance of this was documented in the Vogtle LRA Water Chemistry Program B.3.28.

2. Blistering has also been noted at many plants. Examples include blistering at Seabrook and Beaver Valley.

3. The significant loss of neutron-absorbing capacity of the plate-type carborundum material has been reported at Palisades.

Three spent fuel pool monitoring coupon strings were installed in the VYNPS spent fuel pool storage racks following the replacement of nine racks in 1989. Each monitoring string consists of eight 304L stainless steel coupons and three Boral coupons. Coupon analysis was performed in 1991 and 1996. In 1996, the coupons in one string were dimensionally measured and weighed. No indication of loss of material was observed. Also in 1996, the last Boral coupon in the string exhibited blistering on the bottom side surface of the coupon. This was determined to be cosmetic in nature. Because the blistering observed in 1996 was cosmetic in nature with no degradation of the neutron-absorption capability of the spent fuel racks observed in the five years between surveillance campaigns in 1991 and 1996, it was determined that additional coupon testing was not required and the program was discontinued.

In addition to the above, additional relevant industry operating experience is described in LR-ISG-2009-01. Relevant operating experience will be considered during implementation of this program.

Section A.2.1.37 of Appendix A to the LRA remains unchanged. Section B.1.31 of Appendix B to the LRA is revised to read as follows.

B.1.31 Neutron Absorber Monitoring Program

Program Description

The Neutron Absorber Monitoring Program is a new program that manages loss of material and reduction of neutron absorption capacity of Boral neutron absorption panels in the spent fuel racks. The program will rely on periodic inspection, testing, monitoring and analysis of the criticality design to assure that the required five percent subcriticality margin is maintained during the period of extended operation.

The program will be initiated prior to the period of extended operation. The first testing will be completed by the end of 2014.

Operating Experience

Three spent fuel pool monitoring coupon strings were installed in the VYNPS spent fuel pool storage racks following the replacement of nine racks in 1989. Each monitoring string consists of eight 304L stainless steel coupons and three Boral coupons. Coupon analysis was performed in 1991 and 1996. In 1996, the coupons in one string were dimensionally measured and weighed. No indication of loss of material was observed. Also in 1996, the last Boral coupon in the string exhibited blistering on the bottom side surface of the coupon. This was determined to be cosmetic in nature. Because the blistering observed in 1996 was cosmetic in nature with no degradation of the neutron-absorption capability of the spent fuel racks observed in the five years between surveillance campaigns in 1991 and 1996, it was determined that additional coupon testing was not required and the coupon monitoring was discontinued.

Relevant plant and industry operating experience is presented above and described in LR-ISG-2009-01. This and any future relevant operating experience will be considered during implementation of this program.

Buried Piping

Background

VYNPS provided additional information related to the buried piping program in LRA supplemental information letters dated October 14, 2010 (BVY 10-052) and December 21, 2010 (BVY 10-058). Based on teleconferences held with NRC staff on January 6, 2011 and January 26, 2011 VYNPS is providing the following supplemental information in order to support the staff's evaluation of the program.

Discussion

The minimum length of piping to be visually inspected during each excavation for inspection of the systems in scope of license renewal is 10 linear feet of piping. The length and material composition of buried piping subject to aging management review is provided below by system. The piping lengths are approximate. The fire protection piping is carbon steel and ductile iron which was conservatively assumed to be gray cast iron for the LRA. Ductile iron and gray cast iron have very similar corrosion resistance with ductile iron being less susceptible to selective leaching. Ductile iron has slightly better corrosion resistance than carbon steel.

System	Material	Piping Length (ft.)
Fire protection (FP)	Carbon steel / ductile iron	3705 / 280
Diesel generator fuel oil (DGFO)	Carbon steel	500
Standby gas treatment (SBGT)	Carbon steel	1240
Service water (SW)	Carbon steel	2290

The VYNPS LRA is correct with respect to buried fiberglass fuel oil piping. There is approximately 10 feet of non safety-related buried fiberglass piping in the John Deere diesel fuel oil system. The piping in question is the vent piping for the John Deere diesel fuel oil storage tank. As shown in Table 3.3.2-6, there are no aging effects requiring management for fiberglass in a soil environment. This conclusion is based on the fact that the piping is not exposed to ultraviolet light, ozone or high voltage current, and the piping is well above the water table such that it is neither continuously exposed to water nor subjected to hydraulic pressures whereby the water could penetrate the gelcoat into the underlying laminate and result in blistering, spalling, or cracking. A similar position has been previously accepted at Kewaunee as described in section 3.5.2.3.8 of their Safety Evaluation Report dated January 2011 (NUREG-1958).

As previously stated in letters BVY 10-052 and BVY 10-058, the buried piping in the table above is located well above the water table, has had no failures of the piping due to corrosion of the external surface, and recent inspections have confirmed the coating is in good condition and the backfill is free of debris that could damage the coating. The design of the piping and the conditions in which it is installed provide reasonable assurance that the piping will continue to perform its intended function consistent with VYNPS operating experience.

The locations for inspections during the PEO will be based on assessment of the combination of impact risk and corrosion risk. The impact risk assessment includes the impact of the piping failure on plant operation and the environment and includes criteria such as safety classification, economics (cost of failure) and public risk (internal environment is radioactive or hazardous). The corrosion risk assessment includes evaluation of soil resistivity, soil drainage, piping material, coating, and cathodic protection. The impact risk and the corrosion risk are considered together to determine inspection locations. This ensures that the most susceptible locations will be inspected.

Fire protection system - The design of the fire protection system at VYNPS includes a cross connect that supplies water through an orifice from the service water system to maintain fire protection system pressure. At the normal service water system operating pressure, approximately 30 gpm of water is supplied through the orifice when the fire protection system pressure is at the starting setpoint for the electric fire pump. An unexplained electric fire pump start could indicate a system leak. Whenever an unplanned electric fire pump start occurs, VYNPS staff writes a condition report to initiate an evaluation to determine the cause. The fire protection system pumps are sized to provide adequate system flow to compensate for the 30 gpm that might be lost through valve or piping leakage. Since a start of the fire pump is annunciated in the control room, this constitutes monitoring the activity of equipment equivalent to the jockey pump at an interval not to exceed one month and serves as an effective alternative to excavation and visual inspection in assuring the ability of the fire protection piping to meet its license renewal intended function.

<u>Fuel oil system</u> - During the PEO, two visual inspections of at least 8% of the total length of buried fuel oil piping (~40 feet) will be conducted at least once every 10 years.

<u>Standby gas treatment system</u> - As stated in BVY 10-052, during normal operation, the standby gas treatment system contains stagnant air at atmospheric pressure with trace amounts of radioactive contamination. When the system is in service during surveillance or testing, the buried piping contains filtered air slightly above atmospheric pressure that has passed through carbon and particulate filters such that significant radioactive materials would not be present. Consequently, the impact of SBGT system buried piping degradation would be low and a lower level of inspection than recommended for piping containing hazardous material is appropriate. As indicated in BVY 10-058, a minimum of two ten foot sections of this piping will be inspected prior to the PEO using direct visual examination techniques. During the PEO, at least two visual inspections of buried piping in the standby gas treatment system will be performed every 10 years. Each inspection will be a visual inspection spanning a minimum of 10 feet of piping.

<u>Service water system</u> - The service water system uses water from the Connecticut River. During the PEO, at least two inspections of buried piping in the service water system will be performed every 10 years. Each inspection will be a visual inspection spanning a minimum of 10 feet of piping. VYNPS also performs system flow testing of the alternate cooling system every ten years which verifies the system can deliver adequate flow between safety-related heat exchangers and the alternate heat sink and provides additional assurance that excessive leakage from the portion of the service water system underground and buried piping that performs the alternate cooling system function is not present.

To provide additional assurance that the piping will remain capable of performing its intended function, soil will be sampled prior to the PEO to confirm that the soil conditions are not aggressive. The number of inspections during the PEO will be based on the results of this soil survey. The soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. Soil samples will be taken at a minimum of two locations at least three feet below the surface near the in-scope piping to obtain representative soil conditions for each of the systems. The parameters monitored will include soil composition, pH, chlorides, sulfates, and resistivity. American Water Works Association (AWWA) Standard C105 Appendix A will be used to determine corrosiveness of the soil in addition to soil resistivity measurement. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the number of inspections of the standby gas treatment system and service water system buried piping will be increased to three each and the percentage of fuel oil buried piping inspected will be increased to 12%.

The buried piping inspection and soil measurement results will be incorporated into the risk ranking evaluation to determine the need for additional or more frequent inspections on affected systems. In addition, abnormal buried piping inspection results will be evaluated under the corrective action program to determine the extent of condition and the need for additional inspections. These attributes of the program provide reasonable assurance that the pipe wall thickness will meet acceptable values throughout the period of extended operation.

Inspection Summary

System	10 yr prior to PEO	1st 10 year of PEO	2nd 10 yr of PEO
FP	1 (8')*	System monitoring	System monitoring
DGFO	2 (8% of total)*	8%	8%
SBGT	2 inspections	2 inspections	2 inspections
SW	2 (6' and 8')*	2 inspections	2 inspections

* = Inspection already completed

If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the number of inspections of the standby gas treatment system and service water system buried piping will be increased to three inspections and the inspection regime will be as follows.

System	10 yr prior to PEO	1st 10 year of PEO	2nd 10 yr of PEO
FP	1 (8')*	System monitoring	System monitoring
DGFO	2 (8% of total)*	12%	12%
SBGT	2 inspections	3 inspections	3 inspections
SW	2 (6' and 8')*	3 inspections	3 inspections

* = Inspection already completed

Commitment #54 is revised to read as follows:

Commitment # 54

Prior to the PEO, VYNPS will inspect portions of the standby gas treatment system buried piping. The inspections will consist of direct visual examination of a minimum of two sections of piping and cover the entire circumference of at least ten linear feet of piping in each section.

During the PEO, inspections of two carbon steel piping segments in each of standby gas treatment and service water systems will be performed every 10 years if measured soil resistivity is > 20,000 ohm-cm and the soil scores 10 points or less using AWWA C105. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the number of inspections of the standby gas treatment system and service water system buried piping will be increased to three each. Each of these direct visual inspections following excavation will cover the entire circumference of at least ten linear feet of piping.

During the PEO, two inspections covering at least 8% of the total length of in-scope buried fuel oil piping (~40 feet) will be performed at least once every 10 years. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the percentage of fuel oil buried piping inspected will be increased to 12%.

Soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results.

Section B.1.1 of Appendix B to the LRA remains unchanged. Section A.2.1.1 of Appendix A to the LRA is revised to read as shown below.

A.2.1.1 Buried Piping Inspection Program

The Buried Piping Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, stainless steel, and gray cast iron piping components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. During the PEO, inspections of carbon steel piping segments of standby gas treatment and service water systems will be performed every 10 years. Each of these direct visual inspections following excavation will cover the entire circumference of at least ten linear feet of piping. During the PEO, two inspections will cover at least 8% of the total length of in-scope buried fuel oil piping (~40 feet) at least once every 10 years. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement. The number of inspections will be increased if the results of soil samples indicate aggressive soil conditions.

Non-EQ Inaccessible Medium-Voltage Cables

Background

By letters dated September 3, 2010 (BVY 10-050) and December 21, 2010 (BVY 10-058), VYNPS provided information to enhance the aging management program for non-EQ inaccessible medium-voltage cables. Based on a teleconference held with NRC staff on January 31, 2011, VYNPS is providing the following supplemental information.

Section A.2.1.19 of Appendix A to the LRA and B.1.17 of Appendix B to the LRA are revised to specify that the testing frequency of non-EQ inaccessible medium-voltage cables is at least once every six years for consistency with the test frequency of low-voltage cables within the scope of the program and to specify that the test results will be evaluated to determine if the test frequency should be modified. Section B.1.17 of Appendix B to the LRA is also revised to add a definition of significant moisture to be consistent with Section A.2.1.19 of Appendix A to the LRA. The changes are presented as strikeout text deleted, and underlined text added.

A.2.1.19 Non-EQ Inaccessible Medium-Voltage Cable Program

In the Non-EQ Inaccessible Medium-Voltage Cable Program, medium-voltage cables with a license renewal intended function that are exposed to significant moisture are tested at least once every six years to provide an indication of the condition of the conductor insulation. The specific test performed is a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, polarization index, or other testing that is state-of-the-art at the time the test is performed. Significant moisture is defined as periodic exposures that last more than a few days. The first test will be completed prior to the period of extended operation with the exception of the 4.16 kV cables between the unit auxiliary transformer and Bus 1 and Bus 2. These cables are continuously energized during normal plant operation demonstrating their ability to perform their license renewal intended function. They have no previous evidence of exposure to moisture, are subject to insulation resistance testing during each refueling outage and will be replaced and tested, in conjunction with the unit auxiliary transformer replacement, during the first refueling outage following commencement of the period of extended operation.

Inspections for water collection in cable manholes containing inaccessible low-voltage and medium-voltage cables with a license renewal intended function will occur at least once every year. Additional condition-based inspections of these manholes will be performed based on: a) potentially high water table conditions, as indicated by high river level, and b) after periods of heavy rain. The inspection results are expected to indicate whether the inspection frequency should be modified. <u>The manhole inspection will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and that dewatering/drainage systems (i.e., sump pumps), if installed, and associated alarms operate properly.</u>

Inaccessible low-voltage cables (cables with operating voltage from 400 V to 2 kV) with a license renewal intended function are included in this program. Inaccessible low-voltage cables will be tested for degradation of the cable insulation prior to the period of extended operation and at least once every six years thereafter. A proven, commercially available test will be used for detecting deterioration of the insulation system for inaccessible low-voltage cables potentially exposed to significant moisture.

<u>Failure of the cable test results and manhole inspections to meet the acceptance criteria will require corrective actions. The corrective actions will address modifying the cable test frequency and the manhole inspection frequency.</u>

B.1.17 Non-EQ Inaccessible Medium-Voltage-Cable

<u>Program Description</u>

The Non-EQ Inaccessible Medium-Voltage-Cable Program at VYNPS will be based on and consistent with the program described in NUREG-1801, Section XI.E3, Inaccessible Medium-voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

VYNPS inspection for water accumulation in manholes is conducted in accordance with a plant procedure. An evaluation per the Corrective Action Process will be used to determine the need to revise manhole inspection frequency based on inspection results.

Medium-voltage cables include cables with operating voltage level from 2kV to 35kV. Low-voltage cables include cables with operating voltage ranging from 400 V to 2 kV.

In this program, periodic actions will be taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and removing water, as needed. <u>The manhole inspection will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and that dewatering/drainage systems, if installed, (i.e., sump pumps) and associated alarms operate properly. Significant moisture is defined as periodic exposures that last more than a few days.</u> In scope medium-voltage cables exposed to significant moisture will be tested <u>at least once every six years</u> to provide an indication of the condition of the conductor insulation. The specific type of test to be performed will be determined prior to the initial test and is to be a proven test for detecting deterioration of the insulation system due to wetting as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed.

Inaccessible low-voltage cables (cables with operating voltage from 400 V to 2 kV) with a license renewal intended function are included in this program. A proven, commercially available test will be used for detecting deterioration of the insulation system for inaccessible low-voltage cables potentially exposed to significant moisture. Inaccessible low-voltage cables, with one exception, will be tested for degradation of the cable insulation prior to the period of extended operation and at least once every six years thereafter. <u>The one exception is that the 4.16 kV cables between the unit auxiliary transformer and Bus 1 and Bus 2 will not be tested prior to the period of extended operation. These cables are continuously energized during normal plant operation demonstrating their ability to perform their license renewal intended function. They have no previous evidence of exposure to moisture, are subject to insulation resistance testing during each refueling outage and will be replaced and tested, in conjunction with the unit auxiliary transformer replacement, during the first refueling outage following commencement of the period of extended operation.</u>

<u>Failure of the cable test results to meet the acceptance criteria will require corrective actions. The corrective actions will address modifying the cable test frequency and the manhole inspection frequency.</u>

By letters dated March 12, 2007 and March 23, 2007 VYNPS committed to include testing of the underground medium-voltage cables at the Vernon Hydro Station in the Non-EQ Inaccessible Medium Voltage Cable Program with a testing frequency of at least once every 10 years after the initial test. This was license renewal commitment 43. To be consistent with the changes made to specify the testing frequency for medium-voltage cables within the scope of the program in LRA Sections A.2.1.19 and B.1.17 above, license renewal commitment 43 is revised to read as follows:

<u>Commitment #43</u>

Establish and implement a program that will require testing of the two 13.8 kV cables from the two Vernon Hydro Station 13.8 kV switchgear buses to the 13.8 kV / 69 kV step up transformers before the period of extended operation and at least once every 6 years after the initial test.

<u>Protective Coatings Inside Containment</u>

<u>Background</u>

VYNPS provided additional information related to the Protective Coating Program in LRA supplemental information letter December 21, 2010 (BVY 10-058). In BVY 10-058, VYNPS provided LRA Section A.2.1.38 of Appendix A and B.1.32 of Appendix B to describe the aging management program to manage the effects of aging of the protective coatings inside primary containment, such that they will not degrade and become a debris source that may challenge ECCS performance during the PEO. Based on teleconferences held with NRC staff on January 6, 2011 and January 27, 2011, VYNPS is providing the following supplemental information in order to support the staff's evaluation of the program.

<u>Request</u>:

1. VYNPS was requested to confirm that it will be adopting and complying with all the recommendations in Regulatory Guide (RG) 1.54 Revision 2. If not, VYNPS was requested to describe what exceptions are being taken to the RG 1.54 Revision 2.

<u>Response:</u>

RG 1.54 refers to a number of industry standards that the staff finds acceptable as guidelines for performing activities related to coatings used in nuclear power plants. The scope of the VYNPS Protective Coatings Program is to address management of the effects of aging on

Service Level I coatings applied to steel and concrete surfaces inside containment. As such, the VYNPS Protective Coatings Program will comply with those sections of RG 1.54 Revision 2 that relate to inspection and maintenance of such coatings as addressed under Section C.3 "Training and Qualifications of Nuclear Coating Specialist, Protective Coating Inspectors and Coating Applicators" and Section C.4 "Maintenance of Coating." RG 1.54 endorses ASTM D 5163-08 as acceptable guidance for establishing an in-service coating monitoring program for Service Level I coating systems in operating Nuclear Power Plants. The VYNPS Protective Coatings Program is the same program described in the 10-element program description of NUREG-1801 Section XI.S8. The VYNPS program refers to ASTM D 5163-08 for the specifics of an acceptable aging management program for Service Level I coatings. VYNPS demonstration of compliance with or deviation from the individual elements of RG 1.54 Sections C.3 and C.4 are noted below in *italics*.

<u>RG 1.54 Section C.3</u>

ASTM D 4537-04a, "Standard Guide for Establishing Procedures To Qualify and Certify Personnel Performing Coating Work Inspection in Nuclear Facilities" (Ref. 18), provides guidance that the NRC staff finds acceptable on the qualification and certification of personnel who inspect protective coatings in nuclear facilities. This standard provides guidance on the inspection of the education, training, experience, qualifications, and certification of Service Level I, II, and III coatings inspectors.

In accordance with the recommendations of NUREG-1801, Section XI.S8, the VYNPS Protective Coating Program requires personnel qualification in accordance with paragraph 9 of ASTM D 5163-08. The VYNPS Protective Coating Program will be in compliance with this provision upon completion of the enhancements described in the supplemental information dated December 21, 2010.

ASTM D 5498-09, "Standard Guide for Developing a Training Program for Personnel Performing Coating Work Inspection for Nuclear Facilities" (Ref. 19), provides guidance that the NRC staff finds acceptable for developing a training program for personnel who perform coating work inspection at nuclear facilities.

In accordance with the recommendations of NUREG-1801, Section XI.S8, the Protective Coating Program requires personnel qualification in accordance with paragraph 9 of ASTM D 5163-08. That paragraph specifies that individuals who perform visual assessment and coordinate coating condition assessment shall be the Nuclear Coating Specialist per D7108 or personnel judged acceptable by the Nuclear Coating Specialist. Followup inspections, if needed, shall be by individuals trained in the applicable referenced standards of Guide D5498 and the requirements of licensee's Quality Assurance Program. The VYNPS Protective Coating Program will comply with this provision upon completion of the enhancements described in the supplemental information dated December 21, 2010.

ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist" (Ref. 20), provides guidance that the NRC staff finds acceptable for establishing qualifications for a nuclear coatings specialist. A nuclear coatings specialist must meet one of the combinations of qualification attributes provided in Table 2 of ASTM D 7108-05.

In accordance with the recommendations of NUREG-1801, Section XI.S8, the Protective Coating Program requires personnel qualification in accordance with paragraph 9 of ASTM D 5163-08, which references ASTM D 7108-05. The VYNPS Protective Coating Program will be in compliance with this provision upon completion of the enhancements described in the supplemental information dated December 21, 2010.

ASTM D 4227-05, "Standard Practice for Qualification of Coating Applicators for Application of Coatings to Concrete Surfaces" (Ref. 21), provides guidance that the NRC staff finds acceptable for the qualification of coating applicators to verify that they are proficient and can attain the quality required for the application of specified coatings to concrete surfaces, including those in a nuclear facility.

Coating application is not performed under the Protective Coating Program. The intent of D5163-08 is to provide guidance for coating condition assessments and guidance for the qualification of coating applicators is not provided. Therefore, the provisions of ASTM D 4227-05 are not included in the program.

ASTM D 4228-05, "Standard Practice for Qualification of Coating Applicators for Application of Coatings to Steel Surfaces" (Ref. 22), provides guidance that the NRC staff finds acceptable for the qualification of coating applicators to verify that they are proficient and can attain the quality required for applying specified coatings to steel surfaces, including those in a nuclear facility.

Coating application is not performed under the Protective Coating Program. The intent of D5163-08 is to provide guidance for coating condition assessments and guidance for the qualification of coating applicators is not provided. Therefore, the provisions of ASTM D 4228-05 are not included in the program.

ASTM D 4286-08, "Standard Practice for Determining Coating Contractor Qualifications for Nuclear Powered Electric Generation Facilities" (Ref. 23), provides criteria and methods that the NRC staff finds acceptable to assist utility owners, architects, engineers, and contractors in determining the overall qualifications of a coating contractor to perform coating work for the primary containment and other safety-related facilities of NPPs. The criteria and requirements for coating contractors address their capabilities to perform nuclear coating work.

The Protective Coating Program is a monitoring program. The intent of D5163-08 is to provide guidance for coating condition assessments and guidance for the qualification of coating applicators is not provided. Consequently, the provisions of ASTM D 4286-08, which apply to personnel who apply coatings, are not included in the program. Corrective actions, if required, will be determined in accordance with the VYNPS corrective action program which meets the requirements of 10 CFR 50, Appendix B.

<u>RG 1.54 Section C.4</u>

ASTM D 5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants" (Ref. 24), provides guidelines that the NRC staff finds acceptable for establishing an in-service coating monitoring program for Service Level I coating systems in operating NPPs and for Service Level II and other areas outside containment (as applicable) with the following conditions:

a. Licensees should establish an acceptable condition assessment program using qualified personnel and should perform condition assessments at a periodicity that would allow them to detect potential coating degradation and to implement repairs before such degradation would adversely impact postaccident safety systems.

The VYNPS Protective Coating Program complies with this provision.

b. Licensees should perform condition assessments under the direction of a nuclear coating specialist, as defined in ASTM D 7108-05.

The VYNPS Protective Coating Program will be in compliance with this provision upon completion of the enhancements described in the supplemental information dated December 21, 2010

c. Licensees should evaluate degraded coatings identified during condition assessments for their impact on the ECCS postaccident function consistent with the guidance in RG 1.82 "Water Sources for Long-Term Recirculation Cooling Following a Loss-Of-Coolant Accident," (Ref. 25) and in accordance with applicable licensing-basis documents.

The VYNPS Protective Coating Program complies with this provision.

d. Although the ASTM D 5163-08 standard provides reasonable assurance that qualified coatings left in service after a visual inspection will remain adhered to their substrates under accident conditions, it does not guarantee that visual inspection will detect all degraded coatings. Therefore, the NRC recommends that licensees account for the potential that visual inspections may not identify some degraded coatings by using margin in debris-generation calculations for ECCS strainer performance or by using a debris transport analysis to show that the debris will not reach the strainer.

VYNPS uses the Utility Resolution Guide (URG for ECCS Suction Strainer Blockage Volume 1) recommended values for inorganic zinc top-coated with epoxy as part of its bounding values for qualified coatings as available for transport to the suppression pool.

Further, VYNPS uses the URG recommended values for sludge generation rate as part of its bounding values for total sludge source term in the suppression pool. The VYNPS Protective Coating Program complies with this provision.

Request:

2. VYNPS was requested to discuss which standards other than ASTM 5163-08 it will be using as part of this aging management program.

Response:

In conjunction with ASTM D5163-08, the following ASTM will be used as part of the aging management program in addition to those ASTMs listed in D5163-08, Step 2 "Referenced Documents."

- ASTM D660 for evidence of checking
- ASTM D661 for evidence of cracking
- ASTM D772 for evidence of flaking (scaling)

Additional ASTM standards, which will be used as necessary should degradation be found, are the following.

- ASTM D7091-05, "Standard Practice for Nondestructive Measurement of Dry Film Thickness of Nonmagnetic Coatings Applied to Ferrous Metals and Nonmagnetic, Nonconductive Coatings Applied to Non-Ferrous Metals"
- ASTM D3359, "Test Methods for Measuring Adhesion by Tape Test"
- ASTM D3363, "Standard Test Method for Film Hardness by Pencil Test"

- ASTM D4541, "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers"
- ASTM D4787, "Practice for Continuity Verification of Liquid or Sheer Linings Applied to Concrete Substrates"
- ASTM D5162, "Standard Practice for Discontinuity (Holiday) Testing of Nondestructive Protective Coatings on Metallic Substrates"
- ASTM D6677, "Standard Test Method for Adhesion Testing by Knife"
- ASTM D7234, "Standard Test Method for Pull-Off Adhesion Strength of Coatings on Concrete Using Portable Pull-Off Adhesion Testers"

Request:

3. VYNPS was requested to confirm that it will implement all recommendations outlined in ASTM 5163-08 with no exceptions. If not, VYNPS was requested to discuss these exceptions.

Response:

Vermont Yankee will implement the recommendations outlined in ASTM D5163-08 with no exceptions.

Request:

4. VYNPS was requested to discuss the qualification of inspection personnel to perform these inspections as stated in Enhancement 1.

Response:

The recommended qualifications of a Nuclear Coating Specialist are defined in ASTM D7108, "Standard Guide for Establishing Qualifications for a Nuclear Coating Specialist". In accordance with ASTM D7108, qualification of inspection personnel who perform these inspections shall be as specified in ASTM D4537, "Establishing Procedures to Qualify and Certify Personnel Performing Coating Work Inspection in Nuclear Facilities".

Request:

5. Due to the operating experience at VYNPS as cited in BVY 10-058 (e.g., degradation of coatings, delamination, peeling, flaking, etc.) , discuss and justify the frequency for performing inspections.

Response:

Coating condition assessment frequencies take into consideration a review of documentation regarding the condition of existing coatings. The coatings assessment program is coordinated with existing inspection programs and maintenance activities, when possible. The containment liner (ASME-IWE) inspection, for example, includes a requirement for inspection of the coating when assessing the wall thickness under the IWE program. These inspections are performed at least once every four years. These inspection frequencies were evaluated and determined to be adequate for the condition of the coatings as noted in the operating experience cited in BVY 10-058 because the basecoat was found to be intact and the topcoat showed limited deterioration.

Request:

6. VYNPS was requested to clarify the statement in BVY 10-058, "The evaluation determined that the amount of topcoat loss identified did not threaten performance of the ECCS strainers." More specifically, VYNPS was requested to discuss:
   (a) Was only the topcoat loss evaluated? How was the topcoat debris accounted for in the ECCS evaluation?
   (b) Was the base coat also evaluated? Was the base coat alone a qualified system?

Response:

(a) The base coat and topcoat were included in the evaluation. The ECCS suction strainer evaluation utilizes the Utility Resolution Guideline (URG for ECCS Suction Strainer Blockage Volume 1) as part of establishing the bounding values for coatings available for transport to the suppression pool. All of the coatings in the steam/water zone of influence were assumed to transport to the ECCS strainers. Additional debris is also assumed in order to account for coatings which are unqualified or damaged.

(b) The base coat and topcoat were included in the evaluation. The coating system includes a primer coat (or base coat) of Carboline CZ-11 inorganic zinc, which is a stand-alone qualified coating for the primary containment. Adhesion testing of the base coat was conducted in accordance with ASTM D4541 with satisfactory results.

The following describes how protective coatings in containment will be properly managed so that they do not become an unanalyzed debris source during the period of extended operation by describing the 10 elements of the VYNPS Protective Coating Program.

PROTECTIVE COATING PROGRAM

Program Description

The Protective Coating Program manages the effects of aging on Service Level I coatings inside containment.

Service Level I protective coatings are not credited to manage the effects of aging, however, proper maintenance of protective coatings inside containment is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment. The proper monitoring and maintenance of Level I coatings ensures there is no coating degradation that would impact safety functions.

Evaluation and Technical Basis

1. *Scope of Program:* The program applies to Service Level I coatings applied to steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors). As defined in NRC RG 1.54, Rev. 2, "Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown."

2. *Preventive Action:* The program is a condition monitoring program and does not include preventive actions.

3. *Parameters Monitored or Inspected:*
In accordance with ASTM D 5163-08, parameters monitored or inspected are "any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage."

4. *Detection of Aging Effects:* In accordance with ASTM D 5163-08, paragraph 6, monitoring of coatings inside containment is performed during refueling outages with at least 100% inspected each IWE period, which is maximum of four years. Inspectors and the inspection results evaluator will be qualified in accordance with ASTM D 5163-08, paragraph 9. Inspection plans will be developed and inspection methods will be employed consistent with the recommendations of ASTM D 5163-08, subparagraph 10.1. A general visual inspection is conducted on all readily accessible coated surfaces during a walk-through. After a walk-through, or during the general visual inspection, thorough visual inspections is carried out on previously designated areas and on areas noted as deficient during the walk-through. Inspectors will perform a thorough visual inspection on all coatings near sumps or screens associated with the emergency core cooling system (ECCS). Field documentation of inspection results is performed in accordance with subparagraph 10.3. ASTM D 5163-08, subparagraph 10.5, identifies instruments and equipment that may be needed for inspection.

Enhancement

1. Enhance the Protective Coating Program by clearly defining qualifications for inspection personnel, the inspection coordinator, and the inspection results evaluator, as defined by ASTM D 5163-08 and for inspection to include a thorough visual inspection on all coatings near sumps or screens associated with the Emergency Core Cooling Systems (ECCS).

2. Enhance the Protective Coating Program by clearly identifying the instruments and equipment required for the inspection which include but may not be limited to flashlights, mirrors, measuring instruments, magnifiers, cameras and binoculars.

5. *Monitoring and Trending:* Consistent with ASTM D 5163-08 subparagraph 7.2, prior to beginning the inspection, inspectors will review the previous two inspection reports. In accordance with subparagraph 11.1.2, the inspection report will prioritize repair areas as either needing repair during the same outage or as acceptable for service until future outages, with appropriate surveillance in the interim.

Enhancements

Enhance the Protective Coating Program to specify that the coating inspector conduct a pre-inspection review of the previous two monitoring reports. Also, revise the program to specify that the inspection report prioritize the repair areas as either needing repair during the same outage or as acceptable to postpone to future outages with appropriate surveillance in the interim period.

6. *Acceptance Criteria:* ASTM D 5163-08, paragraph 11, addresses evaluation and documentation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, and prioritization of repairs. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting. ASTM D 5163-08, subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4, provide guidance for the characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies.

Enhancements

Enhance the program to specify the acceptance criteria in accordance with ASTM D 5163-08 and to specify an evaluation of the inspection reports by the responsible coating evaluator who prepares a summary of findings and recommendations for future surveillance or repair.

7. *Corrective Actions:* A recommended corrective action plan is specified for major defective areas so that these areas can be repaired during the same outage, if necessary. The requirements of 10 CFR Part 50, Appendix B, address the corrective actions.

8. *Confirmation Process:* The requirements of 10 CFR Part 50, Appendix B, address the confirmation process.

9. *Administrative Controls:* The requirements of 10 CFR Part 50, Appendix B, address administrative controls.

10. *Operating Experience:*

1. The torus vapor space topcoat is a phenolic resin paint. As early as 1972, there were problems with the topcoat blistering and cracking. This condition was attributed to a "dry spray" condition on the surface of the primer in various places. Early on, the remedy was to scrape off the loose cracked and blistered topcoat and to recoat the areas. Later on, the accepted repair was to scrape off the loose topcoat and not to recoat the inorganic zinc primer. This approach has been followed up to present and is the recommended repair to observed peeling or flaking of topcoat. During the 1998 refueling outage, the lower torus shell surface was blasted and recoated from one foot above the waterline and included all submerged carbon steel surfaces. The steel was coated with a coating Service Level I, design basis accident qualified, inorganic zinc-rich coating which was not top coated, except for a band approximately one foot above and below the water line.

   An inspection of containment coatings was performed by ANSI Level II and III inspectors coincidental with RFO 20 in 1998. The condition of the applied surface coatings of the drywell head, drywell cylinder, drywell sphere, torus vapor space, vent header and vent pipes was inspected in accordance with current ASTM Standards. The coating system in the drywell is either untopcoated Carboline Carbozinc 11 (CZ-11) or CZ-11 topcoated with Keeler and Long 7475 epoxy. Adhesion testing was performed in accordance with ASTM D4541 on the CZ-11 and results were reported as excellent with failure being at the epoxy-glue or epoxy-inorganic zinc interface. The inorganic zinc was tightly bonded and could not be removed. In all areas of the torus inspected, the adhesion of the inorganic zinc to the steel substrate was also satisfactory. Again, the inorganic zinc primer could not be removed from the steel substrate with the test dolly. Similar results were obtained for the vent header interior and the vent pipe interiors.

2. An inspection of the internal surfaces of the torus was conducted during May of 2010. The coating condition on the inspected components below the waterline was excellent. It was noted that the coated surfaces of the columns and downcomers exhibited little to no coating damage or degradation. The condition of the coating on the immersed sections of the shell plates was in excellent condition. Small amounts of delamination of the topcoat were noted within the belly band region; however the coating adjacent to the exposed primer was tightly bonded. One location was identified within the torus that required coating repair due to the discovery of foreign material (tape) beneath the coating surface. That location was below the waterline on Shell Plate 4 in Bay 5. The foreign material was removed and the coating in this area was repaired.

3. An inspection of primary containment was performed in May 2010 to identify areas in the VYNPS drywell having apparent degraded coatings. The results of the coatings inspection indicated that higher elevations of the drywell have experienced more loss of the topcoat than other areas. However the underlying base coat was still present. This condition is attributed to the higher temperatures in the upper elevations of the drywell. Degraded coatings on structures, systems, and components (SSCs) were identified along with an approximate surface area estimate, were documented and evaluated. The evaluation determined that the amount of coating loss identified did not threaten performance of the ECCS strainers.

Conclusion

The VYNPS Protective Coating Program provides reasonable assurance that the effects of aging on Service Level 1 coatings will be managed such that they can continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

Section A.2.1.38 of Appendix A to the LRA is revised to read as follows:

A.2.1.38 Protective Coating Monitoring and Maintenance Program

The Protective Coating Program manages the effects of aging on Service Level I coatings inside containment by means of periodic visual inspections.

Section B.1.32 of Appendix B to the LRA is revised to read as follows:

B.1.32 Protective Coating Program

Program Description

The Protective Coating Program is the program described in NUREG-1801, Section XI.S8, Protective Coating Monitoring and Maintenance Program.

The Protective Coating Program manages the effects of aging on Service Level I coatings inside containment.

Service Level I protective coatings are not credited to manage the effects of aging, however, proper maintenance of protective coatings inside containment is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment. The proper monitoring and maintenance of Level I coatings ensures there is no coating degradation that would impact safety functions.

Operating Experience

1. The torus vapor space topcoat is a phenolic resin paint. As early as 1972, there were problems with the topcoat blistering and cracking. This condition was attributed to a "dry spray" condition on the surface of the primer in various places. Early on, the remedy was to scrape off the loose cracked and blistered topcoat and to recoat the areas. Later on, the accepted repair was to scrape off the loose topcoat and not to recoat the inorganic zinc primer. This approach has been followed up to present and is the recommended repair to observed peeling or flaking of topcoat. During the 1998 refueling outage, the lower torus shell

surface was blasted and recoated from one foot above the waterline and included all submerged carbon steel surfaces. The steel was coated with a coating Service Level I, design basis accident qualified, inorganic zinc-rich coating which was not top coated, except for a band approximately one foot above and below the water line.

An inspection of containment coatings was performed by ANSI Level II and III inspectors coincidental with RFO 20 in 1998. The condition of the applied surface coatings of the drywell head, drywell cylinder, drywell sphere, torus vapor space, vent header and vent pipes was inspected in accordance with current ASTM Standards. The coating system in the drywell is either untopcoated Carboline Carbozinc 11 (CZ-11) or CZ-11 topcoated with Keeler and Long 7475 epoxy. Adhesion testing was performed in accordance with ASTM D4541 on the CZ-11 and results were reported as excellent with failure being at the epoxy-glue or epoxy-inorganic zinc interface. The inorganic zinc was tightly bonded and could not be removed. In all areas of the torus inspected, the adhesion of the inorganic zinc to the steel substrate was also satisfactory. Again, the inorganic zinc primer could not be removed from the steel substrate with the test dolly. Similar results were obtained for the vent header interior and the vent pipe interiors.

2. An inspection of the internal surfaces of the torus was conducted during May of 2010. The coating condition on the inspected components below the waterline was excellent. It was noted that the coated surfaces of the columns and downcomers exhibited little to no coating damage or degradation. The condition of the coating on the immersed sections of the shell plates was in excellent condition. Small amounts of delamination of the topcoat were noted within the belly band region; however the coating adjacent to the exposed primer was tightly bonded. One location was identified within the torus that required coating repair due to the discovery of foreign material (tape) beneath the coating surface. That location was below the waterline on Shell Plate 4 in Bay 5. The foreign material was removed and the coating in this area was repaired.

3. An inspection of primary containment was performed in May 2010 to identify areas in the VYNPS drywell having apparent degraded coatings. The results of the coatings inspection indicated that higher elevations of the drywell have experienced more loss of the topcoat than other areas. However the underlying base coat was still present. This condition is attributed to the higher temperatures in the upper elevations of the drywell. Degraded coatings on structures, systems, and components (SSCs) were identified along with an approximate surface area estimate, were documented and evaluated. The evaluation determined that the amount of coating loss identified did not threaten performance of the ECCS strainers.

References:
1. Letter, Entergy to USNRC, "License Renewal Application Supplemental Information," BVY 10-052, dated October 14, 2010
2. Letter, Entergy to USNRC, "License Renewal Application Supplemental Information," BVY 10-058, dated December 21, 2010
3. Letter, Entergy to USNRC, "License Renewal Application Supplemental Information," BVY 10-050, dated September 3, 2010

Attachment 2

Vermont Yankee Nuclear Power Station
License No. DPR-28 (Docket No. 50-271)

List of License Renewal Commitments

VERMONT YANKEE NUCLEAR POWER STATION
LICENSE RENEWAL COMMITMENT LIST

During the development and review of the Vermont Yankee Nuclear Power Station License Renewal Application, Entergy made commitments to provide aging management programs to manage the effects of aging on structures and components during the extended period of operation. The following table lists the revised license renewal commitments made in this submittal, along with the implementation schedule and the source of the commitment.

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No./ Comments
43	Establish and implement a program that will require testing of the two 13.8 kV cables from the two Vernon Hydro Station 13.8 kV switchgear buses to the 13.8 kV / 69 kV step up transformers before the period of extended operation and at least once every 6 years after the initial test.	March 21, 2012	BVY 07-009 BVY 07-018 BVY 11-010	Am. 24 Response to: RAIs 3.6.2.2-N-08-2 3.6.2.2-N-08-4

ITEM	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	Related LRA Section No./ Comments
54	Prior to the PEO, VYNPS will inspect portions of the standby gas treatment system buried piping. The inspections will consist of direct visual examination of a minimum of two sections of piping and cover the entire circumference of at least ten linear feet of piping in each section. During the PEO, inspections of two carbon steel piping segments in each of standby gas treatment and service water systems will be performed every 10 years if measured soil resistivity is > 20,000 ohm-cm and the soil scores 10 points or less using AWWA C105. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the number of inspections of the standby gas treatment system and service water system buried piping will be increased to three each. Each of these direct visual inspections following excavation will cover the entire circumference of at least ten linear feet of piping. During the PEO, two inspections covering at least 8% of the total length of in-scope buried fuel oil piping (~40 feet) will be performed at least once every 10 years. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the percentage of fuel oil buried piping inspected will be increased to 12%. Soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results.	March 21, 2012	BVY 10-052 BVY 10-058 BVY 11-010	A.2.1.1, A.2.1.32 B.1.1 Audit Report dated 9/3/10