August 23, 2012

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket Nos. 50-247-LR/ 50-286-LR
	)	
(Indian Point Nuclear Generating Units 2 and 3)	)	

NRC STAFF'S STATEMENT OF POSITION ON CONTENTION NYS-5 (BURIED PIPES AND TANKS)

In accordance with 10 C.F.R. § 2.1207(a) and the Atomic Safety and Licensing Board's ("Board") Orders in this proceeding,[1] the NRC Staff ("Staff") hereby submits its Statement of Position ("Statement") on the State of New York's ("New York" or "NYS") Contention NYS-5 (Buried Pipes and Tanks). This Statement is supported by the prefiled written testimony of Kimberly J. Green and William C. Holston ("Staff Testimony") (Exhibit NRCR00016), and the exhibits cited therein (including Exhibits NRC000017 through NRC000029, NRC000162, and NRC000163).

Contention NYS-5 generally challenges the adequacy of the aging management program ("AMP") for buried pipes and tanks at Indian Point Nuclear Generating Units 2 and 3 ("IP2" and "IP3"), to manage the effects of aging on buried pipes and tanks that may contain radioactive fluids during the period of extended operation. The Staff has carefully considered the assertions presented in this contention, as amplified in the testimony of New York's expert,

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[1] *See* (1) "Order (Granting NRC Staff's Unopposed Time Extension Motion and Directing Filing of Status Updates)" (Feb. 16, 2012), at 1; (2) "Order (Clarification of Procedures for Evidentiary Filings)" (Oct. 18, 2011), at 2-3; (3) "Order (Procedures for Evidentiary Filings)" (Oct. 7, 2011), at 2; and (4) "Scheduling Order" (July 1, 2010), at 14.

Dr. David Duquette (Exhibit NYS000164), and the exhibits filed in support thereof. For the reasons set forth below and in the testimony filed herewith, the Staff respectfully submits that Contention NYS-5 is lacking in merit and should be resolved in favor of Entergy Nuclear Operations, Inc. ("Entergy" or "Applicant") and the Staff.

BACKGROUND

Contention NYS-5 was filed by New York on November 30, 2007. As filed by New York, the contention stated as follows:

> NYS-5
> The aging management plan contained in the license renewal application violates 10 C.F.R. §§ 54.21 and 54.29(a) because it does not provide adequate inspection and monitoring for corrosion or leaks in all buried systems, structures, and components that may convey or contain radioactively-contaminated water or other fluids and/or may be important to plant safety.

"New York State Notice of Intention to Participate and Petition to Intervene" (Nov. 30, 2007) ("NY Petition"), at 80. This contention was restated by the Atomic Safety and Licensing Board ("Board") in its "Memorandum and Order (Ruling on Petitions to Intervene and Requests for Hearing)" ("Order"), LBP-08-13, 68 NRC 43 (July 31, 2008), to state as follows:

> NYS-5
> The LRA does not provide [an] adequate AMP for buried pipes, tanks, and transfer canals that contain radioactive fluid that meet 10 C.F.R. § 54.4(a) criteria. In addition, the LRA is not clear whether an AMP for IP1 buried SSCs that are being used by IP2 and IP3 exists and whether the LRA is adequate if it does exist.

LBP-08-13, 68 NRC at 218.

The bases for Contention NYS-5 were set forth in New York's Petition at pages 80-92. As set forth therein, and as summarized by the Board in LBP-08-13, New York generally asserted that the buried piping and tank AMP for IP2 and IP3 is inadequate in that (a) there is no adequate program to replace buried structures, systems and components ("SSCs") that convey or contain radioactively-contaminated water and/or other fluids (including underground pipes, tanks and transfer canals), before a leak occurs; (b) there is no adequate inspection or monitoring program to determine if and when leakage occurs; and (c) buried SSCs at Indian Point Unit 1 ("IP1") that will be used for IP2 and IP3 during the period of extended operation ("PEO") are subject to the same inadequacies. *See* LBP-08-13, 68 NRC at 78. In sum, Contention NYS-5 asserts that the AMP fails to provide adequate programs for leak prevention and the inspection, replacement, and monitoring of buried piping and tanks that convey or contain radioactively contaminated fluids.

In support of this contention, New York asserted that buried SSCs are exposed to possible corrosion which jeopardizes the integrity of these SSCs and their ability to perform their intended safety function (LBP-08-13, 68 NRC at 78). According to New York, the "Buried Piping and Tanks Inspection Program," located in LRA Appendix B.1.6, is inadequate, in that (a) the inspection period specified in the LRA and AMP will not prevent or provide early detection of potential leaks; and (b) the LRA and AMP fail to provide an evaluation of the baseline conditions of the buried systems or their welded joints, and do not specify potential corrosion rates. New York further asserted that the buried SSCs of concern here, i.e., the buried SSCs which "may contain radioactive water," "whether by design or a structural or system failure" are the (1) safety injection system, (2) service water system, (3) fire protection system, (4) fuel oil system, (5) security generator system, (6) city water system, (7) plant drain systems, (8) auxiliary feedwater system, and (9) heating system. NY Petition at 81-82.

In its Memorandum and Order admitting this contention, the Board limited the contention "to the extent that it pertains to the adequacy of Entergy's AMP for buried pipes, tanks, and transfer canals that contain radioactive fluid which meets 10 C.F.R. § 54.4(a) criteria" -- stating that the issues for hearing "include, *inter alia*, whether, and to what extent, inspections of buried SSCs containing radioactive fluids, a leak prevention program, and monitoring to detect future excursions are needed as part of Entergy's AMP for these components," including "the adequacy of the AMP for IP1-buried SSCs that are being used by IP2 and IP3" during the license renewal period." LBP-08-13, 68 NRC at 81.

Subsequent to the Board's admission of Contention NYS-5, New York withdrew its assertions regarding (a) spent fuel pool transfer canals and (b) internal corrosion of buried pipes and tanks, as set forth in a "Joint Stipulation" filed by the parties on January 23, 2012.[2] Accordingly, those issues are beyond the scope of the outstanding issues in this contention.

DISCUSSION

A. Regulatory Requirements and Guidance

The Commission's requirements governing the management of aging for structures, systems and components ("SSCs") at a nuclear power plant, including buried and underground piping and tanks, are set forth in 10 C.F.R. §§ 54.4 ("Scope"), 54.21(a)(3) ("Contents of Application") and 54.29(a) ("Standards for Issuance of Renewed License"). These regulations state, in pertinent part, as follows:

> **54.4 Scope**
> (a) Plant systems, structures, and components within the scope of this part are--
> (1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--
> (i) The integrity of the reactor coolant pressure boundary;
> (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or
> (iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable.

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[2] *See* "State of New York, Entergy Nuclear Operations, Inc., and NRC Staff Joint Stipulation" (Jan. 23, 2012), at 1-2, ¶¶ 1-2.

(2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.

(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

(b) The intended functions that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section.

54.21 Contents of application-technical information.
Each application must contain the following information:

(a) *An integrated plant assessment (IPA).* The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries,

> breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and
>
> (ii) That are not subject to replacement based on a qualified life or specified time period.
>
> * * *
>
> (3) For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.
>
> **54.29 Standards for issuance of a renewed license**
> A renewed license may be issued by the Commission up to the full term authorized by § 54.31 if the Commission finds that:
>
> (a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations. These matters are:
>
> (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21(a)(1); . . . . [3]

In addition, the Commission has issued regulatory guidance pertaining to buried and underground piping and tanks, as set forth in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" ("SRP-LR") (September 2005) (Exhibit NYS000195) and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (September 2005) (Exhibit NYS000146A-C).

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[3] 10 C.F.R. § 54.29(a)(2) pertains to time-limited aging analyses, and is inapplicable to this contention concerning an aging management program.

As described in the Staff's Testimony (Exhibit NRCR00016 at 11-13), specific guidance concerning the AMPs which the Staff would find to be acceptable is provided in the GALL Report, NUREG-1801 (Exhibit NYS000146A-C). The GALL Report contains the NRC's approved set of recommendations related to "preventive actions", "mitigative actions", "condition monitoring", and "performance monitoring" as applicable to the component and material type, the environment to which the items are exposed (e.g., raw water, soil, outdoor air), and the aging effect which is being managed. This is documented in a series of NRC-approved AMPs described in the GALL Report (*e.g.,* AMP XI.M20, "Open-Cycle Cooling Water System"; AMP XI.M30, "Fuel Oil Chemistry"; and AMP XI.M34, "Buried Piping and Tanks Inspection"). For example, GALL Report AMP XI.M34 contains "preventive actions" (e.g., coatings) and "condition monitoring" recommendations.[4] In December 2010, the Staff issued GALL Report Revision 2, in which the Staff added AMP XI.M41 for "Buried and Underground Piping and Tanks" (Exhibit NYS000147A-D).[5]

An applicant can take credit for a program described in the GALL Report such that its AMP would be found acceptable, in one of three ways:

1) It may establish a program that is completely consistent with all the recommendations in the GALL Report, or

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[4] "Mitigative actions" (i.e., actions that slow the effects of aging) are included in some aging management programs, such as those associated with controlling the fuel oil chemistry to minimize internal corrosion in the buried fuel oil lines; "performance monitoring" consists of testing the ability of an SSC to perform its intended function; "condition monitoring" recommendations consist of piping and tank inspections. Exhibit NRCR00016, at 12.

[5] Inasmuch as AMP XI.M41 was issued after Entergy submitted its LRA, the Staff has not applied this AMP to the IP2/IP3 LRA; nonetheless, as discussed below and in the Staff's testimony filed herewith, the Staff, through a series of RAIs (see response to Question 16), evaluated the Applicant's AMP against key elements of AMP XI.M41 and the draft ISG for AMP XI.M41 (e.g., number of inspections, soil sampling, and use of plant specific operating experience), and concluded that Entergy's AMP (as revised through its responses to the Staff's RAIs) is adequate to manage the applicable aging effects to ensure that buried piping and tanks will perform their current licensing basis functions. Exhibit NRCR00016, at 12 n.12.

2) It may establish a program that is consistent with the GALL Report with exception(s) to certain portion(s) of the GALL Report that the applicant does not intend to implement, and/or it may state enhancements, revisions or additions to existing aging management programs that the applicant commits to implement prior to the period of extended operation to ensure that its AMP is consistent with the GALL Report AMP. Enhancements may expand, but not reduce the scope of an AMP, or

3) If an applicant's facility has specific materials, environments, aging effects and/or plant-specific operating experience for which aging cannot be effectively managed by any of the GALL Report AMPs, the applicant may develop a plant-specific program that meets the recommended format and content of an AMP as set forth in Section A.1.2.2, Aging Management Program for License Renewal, NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants.

Staff Testimony (Exhibit NRCR00016), at 12-13. The Staff evaluates an applicant's AMPs and its applicable exceptions and enhancements to ensure they provide reasonable assurance that the effects of aging will be adequately managed so that the in-scope system, structure or component's intended function(s) will be maintained consistent with the current licensing basis ("CLB") for the period of extended operation. *Id.* at 13.

B. <u>Buried Piping and Tanks at Indian Point Unit 1</u>

As discussed above (at 3 and 4), Contention NYS-5 includes an assertion that buried SSCs at Indian Point Unit 1 ("IP1") that will be used for IP2 and IP3 during the period of extended operation ("PEO") are subject to the same inadequacies as the IP2 and IP3 buried piping and tanks. As discussed below and in the Staff's testimony, the Staff has carefully considered this assertion and has determined it is without merit.

In particular, Staff witness Kimberly Green presented the Staff's views regarding the adequacy of the Applicant's AMP for buried piping and tanks, to the extent that IP2 and IP3 use or rely upon IP1 buried piping and tanks. Ms. Green is a Senior Mechanical Engineer in the

NRC Division of License Renewal ("DLR"), Office of Nuclear Reactor Regulation ("NRR"). A statement of her professional qualifications was submitted as Exhibit NRC000017.

Ms. Green has substantial experience in conducting technical reviews of aging management programs and aging management review results related to auxiliary and steam and power conversion systems in license renewal applications. In addition, from April 2007 until April 2011, she served as the project manager responsible for the Staff's safety review of the LRA for Indian Point Units 2 and 3. Staff Testimony (Exhibit NRCR00016), at 2.

As part of her official responsibilities, Ms. Green was principally responsible for preparation and issuance of the Staff's "Safety Evaluation Report with Open Items Related to the License Renewal of IP2 and IP3" issued in January 2009, and the "Safety Evaluation Report Related to the License Renewal of IP2 and IP3," NUREG-1930 ("SER"), published in November 2009 (Exhibit NYS000326A-F). In addition, she served as a member of the Staff's audit teams which evaluated the Applicant's scoping and screening methodology, AMRs, and AMPs. As pertinent to Contention NYS-5, she served as one of the Staff's technical reviewers of the AMP for buried piping and tanks in Entergy's LRA for IP2/IP3, and she prepared Section 3.0.3.1.2 concerning buried piping and tanks in the Staff's SER for the IP2/IP3 LRA. In addition, as part of her responsibilities, she reviewed the adequacy of the scoping methodology that Entergy utilized in determining which SSCs should be included within the scope of license renewal for IP2 and IP3, including SSCs at Indian Point Unit 1. Staff Testimony (Exhibit NRC000016), at 3.

In her testimony, Ms. Green describes the scoping review that was conducted by the Staff of the LRA for IP2 and IP3. Further, she describes the bases for the Staff's conclusion that the Applicant had properly included, within the scope of license renewal, the buried piping and tanks at IP1 that may be used or relied upon by SSCs within the scope of license renewal for IP2 and/or IP3, and have an intended function that meet the requirements of 10 C.F.R. § 54.4(a).

As stated by Ms. Green, the Staff reviewed the adequacy of the AMP for in-scope buried piping and tanks for license renewal of IP2 and IP3, including in-scope IP1 SSCs that are used or relied upon by IP2 and/or IP3. To the extent that SSCs are within the scope of license renewal and are subject to an aging management review, the Staff determined that the Applicant's AMP manages the aging of those SSCs. Based on this review, the Staff determined that the aging management program for in-scope buried piping and tanks, including IP1 buried piping and tanks that are used or relied upon by SSCs at IP2 and IP3, is acceptable. Staff Testimony (Exhibit NRCR00016), at 13-14.

Further, the Staff found no merit in New York's view that the LRA does not specifically commit to conducting any inspections of buried piping and tanks at IP1 that are used or relied upon by Indian Point Units 2 and 3 SSCs within the scope of license renewal. In this regard, Ms. Green cited LRA Section 1.3, Plant Description (Exhibit ENT00015A), finding that the Applicant had explicitly stated that IP1 systems and components were considered during the license renewal scoping process, i.e., it considered which IP1 systems have intended functions that satisfy any of the criteria in 10 C.F.R. § 54.4(a) for IP2 and IP3:

> Although the extension of the IP1 license is not a part of this license renewal application, IP1 systems and components interface with and in some cases support the operation of IP2 and IP3. <u>Therefore, IP1 systems and components were considered in the scoping process (see Section 2.1.1).</u> <u>The aging effects of Unit 1 SSCs within the scope of license renewal for IP2 and IP3 will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis throughout the period of extended operation</u>.

LRA (Exhibit ENT00015A) at 1-7; emphasis added. In addition, in LRA Section 2.1.1, Scoping Methodology, the Applicant stated:

> The component database for IP2 and IP3 was used to develop a list of plant systems. The database provides component level information, including the system, component name and identification, quality assurance (QA) classification, location, and other relevant information. The database is in two parts, one for

> IP2, which includes listings for Indian Point Unit 1 (IP1) systems and components, and a second part for IP3. Although the extension of the IP1 license is not a part of this license renewal application, IP1 systems and components interface with and in some cases support the operation of IP2 and IP3. The systems and components needed to support the intended functions for IP2 and IP3 are included in the scope of this license renewal application, regardless of the unit designation of the system or component.

Staff Testimony (Exhibit NRCR00016) at 14-15, citing LRA (Exhibit ENT00015A) at 2.1-2; emphasis added.

Other portions of the LRA provide further information about the IP1 SSCs that are included within the scope of license renewal. In addition, in the following portions of LRA Section 2.3, as amended by Entergy's responses to the Staff's RAIs, the Applicant stated that IP1 systems provide support to, or interface with the following IP2 and IP3 systems:

2.3.3.4 Compressed Air
2.3.3.8 Heating, Ventilation and Air Conditioning
2.3.3.10 Control Room Heating, Ventilation and Cooling
2.3.3.11 Fire Protection – Water
2.3.3.12 Fire Protection – CO2, Halon, and RCP Oil Collection Systems
2.3.3.13 Fuel Oil
2.3.3.17 City Water
2.3.3.18 Plant Drains
2.3.3.19 Miscellaneous Systems in Scope for (a)(2):
Auxiliary Steam
Intake Structure System
Integrated Liquid Waste Handing
Nuclear Service Grade Makeup
Boiler Blowdown

2.3.4.5 IP2 AFW Pump Room Fire Event.[6]

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[6] The IP2 AFW Pump Room Fire Event is served by the Fresh Water Cooling, River Water Service, Station Air, and Water Treatment Plant systems at IP1.

Moreover, in each of the LRA sections identified above, as revised by Entergy in its responses to the Staff's RAIs, the Applicant described the portion of the IP1 system that is used by or relied upon by IP2 and/or IP3. For example, see LRA Section 2.3.3.17 (Exhibit ENT00015A), at page 2.3-140. Plant drawings provided with the LRA provide further information about which SSCs at the facility are within the scope of license renewal. As discussed below, not all of these SSCs at IP1 include buried piping or tanks. Staff Testimony (Exhibit NRCR00016) at 15-16.[7]

Based upon a review of the LRA, and in particular, the IP2 and IP3 systems that were identified as having an interface with, or being supported by, IP1 systems (listed in the Staff's testimony) the Staff concluded that there are no buried tanks at IP1 that are within the scope of license renewal, and that the only buried piping at IP1 that is within the scope of license renewal is included in the city water, river water, and firewater systems. *Id.* at 16.

As Ms. Green explained, to determine which portions, if any, of IP1 systems are within the scope of license renewal, the Staff reviewed the pertinent sections of the LRA (e.g., LRA Section 2.3.3.17) (Exhibit ENT00015A), the sections of the UFSARs for IP1, IP2, and IP3 cited in the LRA, as well as other sections of the UFSARs deemed appropriate by the Staff, along with the corresponding license renewal drawings. Additionally, the Staff reviewed additional CLB documents such as license amendments, as necessary, to attain a good understanding of which SSCs at IP1, IP2, and IP3 should be included within the scope of license renewal. Based on this information, the Staff confirmed that the Applicant's defined scoping boundary, meaning the portion of the system that supports the intended functions of a system within the scope of

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[7] Subsequent to the Staff's issuance of SER Supplement 1, the Applicant notified the Staff of a correction to the LRA; specifically, in a letter dated January 30, 2012 (Exhibit NRC000021),the Applicant noted that, based on the IP2 AFW Pump Room Fire Event, a buried portion of the IP1 river water system was determined to be in scope for purposes of IP2/IP3 license renewal The Applicant therefore revised LRA Table 3.4.2.5 11 IP2 to include the buried IP1 river water system piping components. Staff Testimony (Exhibit NRCR00016) at 16.

license renewal (i.e., those functions that are the basis for including the SSC within the scope of license renewal in accordance with 10 C.F.R. § 54.4(a)(1) through (a)(3), is adequate. As documented in the SER, the Staff concluded for each system that the Applicant has appropriately identified the components that are within the scope of license renewal, as required by 10 C.F.R. § 54.4(a), and those components that are subject to an aging management review (AMR), as required by 10 C.F.R. § 54.21(a)(1). *See* SER § 2.3A.3.17 (Exhibit /NYS000326A), at 2-103. This determination included consideration of the IP1 SSCs that are included or relied upon by SSCs at IP2 and/or IP3 and are within the scope of license renewal. Staff Testimony (Exhibit NRCR00016) at 16-17.

In addition, Ms. Green explained that the summary of aging management review tables in Section 3 of the LRA identify, by system, the component, material, environment, aging effect, and aging management program for each component type that is within the scope of license renewal and subject to an AMR. As defined in LRA table 3.0.1, the service environment for "soil" is defined as "external environment for components buried in the soil, including groundwater in the soil for component." The types of components listed in the summary of aging management review tables in Section 3 of the LRA whose external environment is stated as "soil" are considered to be buried components. *Id.* at 17.

Finally, Ms. Green stated that in preparing to testify in this proceeding, she reviewed the Staff's SER, the LRA, the license renewal drawings, pertinent UFSAR sections, and the Applicant's identification of structures, systems and components ("SSCs") that are within the scope of license renewal. Based on that review, she concluded that the IP2/IP3 SSCs that are within the scope of license renewal appropriately include the IP1 buried piping that is used or relied upon by IP2 and/or IP3 and is within the scope of license renewal. *Id.*

C. <u>In-Scope Buried Piping and Tanks That May Contain Radioactive Fluids</u>

Staff witness William C. Holston presented the Staff's views with respect to the adequacy of the Applicant's AMP for buried piping and tanks, including the systems that are within the scope of Contention NYS-5. Mr. Holston is a Senior Mechanical Engineer in the NRC Division of License Renewal ("DLR"), Office of Nuclear Reactor Regulation ("NRR"). A statement of his professional qualifications was submitted as Exhibit NRC000018.

Mr. Holston is responsible for conducting technical reviews of aging management programs and aging management reviews for SSCs within the scope of license renewal (e.g., pipe, tanks, valves) for a variety of materials, component types and aging effects. In particular, Mr. Holston serves as the lead DLR reviewer for buried and underground piping and tank AMPs and related issues. He has conducted reviews of these AMPs and the related AMRs for buried and underground SSCs in the license renewal applications for sixteen nuclear power plants. He also provided peer review input for recent changes to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," contained in Revision 2 thereof, which resulted in issuance of new AMP XI.M41, "Buried and Underground Piping and Tanks" (Exhibit NYS000147A-D). In addition, he is the author of draft Interim Staff Guidance ("ISG") LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Aging Management Program XI.M41 'Buried and Underground Piping and Tanks'" (Exhibit NRC000019), released for public comment on March 9, 2012, at 77 Fed. Reg.14,446 (Exhibit NRC000020), and the final version of LR-ISG-2011-03 (Exhibit NRC000162) issued on August 2, 2012, 77 Fed. Reg. 46,127 (NRC000163). The ISG addresses preventive actions and inspection recommendations for nuclear power plants reviewed under GALL Report Revision 2 that have buried piping and tanks without cathodic protection. Staff Testimony (Exhibit NRCR00016) at 2-3.

Mr. Holston served as the Staff's principal reviewer of Entergy's AMPs for buried and underground piping and tanks for the IP2/IP3 LRA, from January 2011 to the present. As part of his responsibilities, he prepared two Requests for Additional Information ("RAIs") that were issued by the Staff regarding buried and underground piping and tanks at Indian Point, as a result of recent industry operating experience related to buried and underground piping and tanks; in addition, he served as the Staff's technical reviewer of the Applicant's response to these RAIs. He also served as the author of Section 3.0.3.1.2, "Buried Piping and Tanks Inspection Program," in NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Units 2 and 3," Supplement 1 (August 2011) ("SER Supplement 1") for the IP2/IP3 LRA (Exhibit NYS000160). Staff Testimony (Exhibit NRCR00016) at 4.

Mr. Holston reviewed the nine systems listed by New York in Contention NYS-5 as systems that "may contain radioactive fluid." He found that those nine systems can be categorized as either (a) systems containing radioactive fluid, (b) systems that could potentially contain radioactive fluid in abnormal operations, or (c) systems that are unlikely to contain radioactive fluid. *Id.* at 18. As explained by Mr. Holston, these systems are as follows:

(a) Systems containing radioactive fluids

LRA Section B.1.6, Buried Piping and Tanks Inspection, states that, of the systems that are in-scope for license renewal, "only the safety injection system contains radioactive fluids during normal operations." The Staff determined, however, that one other system within the scope of license renewal may contain radioactive fluids, as stated in the "Indian Point Nuclear Generating Unit 2 – NRC Integrated Inspection Report 05000247/2009-002" ("Integrated Inspection Report"), which was transmitted in a letter from M. Gray (NRC) to J. Pollock (Entergy) dated May 14, 2009 (Exhibit NRC000022). The Integrated Inspection Report discussed the finding of tritium in leakage from the IP2 auxiliary feedwater system ("AFWS") that was associated with a condensate storage tank ("CST") return line leak. The Integrated Inspection Report noted:

> Entergy analyzed the water leaking up through the sleeve and determined it was CST water based on hydrazine and tritium levels. The amount of tritium detected in the water was consistent with that found in the CST, for example, analyses of samples of water from the leak returned 2000 - 2300 picocuries per liter (pCi/l). The release was determined to be below the NRC regulatory limits for liquid effluents. For added perspective, while not drinking water, the Environmental Protection Agency environmental limit for drinking water requires tritium levels less than 20,000 pCi/l.

Accordingly, the Staff determined that, in addition to the safety injection system, the IP2 auxiliary feedwater system may contain radioactive fluids during normal operations. Staff Testimony (Exhibit NRCR00016) at 18.

(b) Systems that could contain radioactive fluids in abnormal operations

Mr. Holston further explained that certain systems that do not contain radioactive fluids during normal operations could become contaminated during abnormal operations, due to their interface with other plant systems that contain radioactive fluids. Based on his review of LRA Section 2.3.3.2 (Exhibit ENT00015A), Mr. Holston concluded that the service water system could become radioactively contaminated due to its interface with the component cooling water ("CCW") system, if the CCW system were contaminated and leakage occurred across heat exchanger tubing; it is unlikely that contamination in the service water system would go undetected because the system has radiation monitoring equipment designed to detect such leakage. Similarly, the city water system could become contaminated due to its interface with the AFWS, if leakage from the AFWS across multiple check valves or normally shut valves were to occur; it is unlikely that this contamination would occur, however, because the city water system is only used as a backup to the AFWS during abnormal events, and it supplies the AFWS by gravity feed, so that flow occurs from the city water system to the AFWS. Likewise, as indicated in LRA Section 2.3.3.18 (Exhibit ENT00015A), the plant drain system could become contaminated because it interfaces with areas that process liquid wastes. Staff Testimony (Exhibit NRCR00016) at 19.

(c) Systems that are unlikely to contain radioactive fluids

Mr. Holston then reviewed other systems at Indian Point. He concluded, based on his experience, including having served as Site Engineering Director at two nuclear power plants, that it is extremely unlikely that any other in-scope buried piping or tanks at IP1, IP2 or IP3 would ever contain radioactive materials. This conclusion is based on the fact that there are no interfaces between these systems (e.g., heat exchangers or potentially leaking isolation check valves) with systems that contain radioactive fluids. During the Staff's review of the IP2 AFW Pump Room Fire Event, the licensee updated its LRA (a) by letter dated June 12, 2009, including buried portions of the circulating water system at IP2 (Exhibit NRC000023), and (b) by letter dated January 30, 2012, adding portions of the buried river water system at IP1 as in-scope components subject to aging management review (Exhibit NRC000021). Neither of these systems are likely to contain radioactive fluids, because they do not interface with potentially contaminated systems. Staff Testimony (Exhibit NRCR00016) at 19-20.

(d) Systems that are not in-scope for purposes of license renewal

Finally, Mr. Holston examined the list of systems presented in Contention NYS-5, and concluded that not all of the nine systems listed in the contention are within the scope of license renewal. Mr. Holston stated that, based on his review of the LRA, in particular the scoping and screening portion, and 10 C.F.R. § 54.4(a), the heating system (one of the nine systems listed in Contention NYS-5) is not an in-scope system for purposes of license renewal. This conclusion is consistent with 10 C.F.R. § 54.4(a), in that the heating system does not perform an intended function which would require it to be within the scope of license renewal. Staff Testimony (Exhibit NRCR00016) at 20.

D. General Principles Concerning the Adequacy of the Applicant's AMP for Buried Piping and Tanks at Indian Point

Following his review of the above matters, Mr. Holston presented a thorough discussion of the Applicant's AMP for buried piping and tanks, and the Staff's conclusion regarding the adequacy of that AMP, as it relates to Contention NYS-5.

As Mr. Holston explained, in Section 3.0.3.1.2 of the Staff's SER (Exhibit NYS000326B) and SER Supplement 1 (Exhibit NYS000160), the Staff presented its determination that the Applicant's aging management program for buried piping and tanks is adequate to manage the effects of aging such that the in-scope buried SSC functions will be maintained consistent with the CLB for the period of extended operation. The Applicant's AMP describes plans for an extensive series of inspections for external corrosion. As set forth in Section 3.0.3.1.2 of the Staff's SER and SER Supplement 1, the Applicant's aging management program for buried piping and tanks fulfills applicable regulatory criteria, including requirements, among others, that (a) in-scope SSC functions will be maintained consistent with the CLB for the period of extended operation, and (b) actions have been identified and have been or will be taken such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB. Staff Testimony (Exhibit NRCR00016) at 20-21, citing SER (Exhibit NYS000326B) and SER Supplement 1 (Exhibit NYS000160), Section 3.0.3.1.2.

In this regard, the Staff made the following specific findings in Section 3.0.3.1.2 of the SER and SER Supplement 1:

> *Original SER:*
>
> On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff

> also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).
>
> *SER Supplement 1:*
>
> On the basis of its review of the applicant's response to RAIs 3.0.3.1.2-1, 3.0.3.1.2-2, and 3.0.3.1.2-3, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Staff Testimony (Exhibit NRCR00016) at 21.

Turning to Contention NYS-5, Mr. Holston stated his disagreement with New York's contention that the LRA does not provide an adequate AMP for in-scope buried pipes and tanks that contain radioactive fluid. As he explained, based on a review of the LRA and the Applicant's answers to several RAIs related to buried piping and tanks of the Indian Point facility, the Staff has concluded that the AMP for buried piping and tanks at the facility will adequately manage the effects of aging for the in-scope components so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation. As documented in SER Supplement 1, Section 3.0.3.1.2 (Exhibit NYS000160), the basis for this determination may be summarized as follows:

- In regard to preventive actions to mitigate potential corrosion, all steel piping has been coated in accordance with standard industry practices. Recent excavated direct visual examinations of buried pipe have demonstrated that the coatings are in acceptable condition and the backfill in the vicinity of the pipe has not damaged the coatings.

- The Applicant has committed to sample the soil for corrosivity prior to and during the period of extended operation, using standard industry methodologies to determine soil corrosivity, and will increase the number of inspections if the soil is found to be corrosive.

- The Applicant is risk informing its piping inspection locations to select those with the greatest potential for leakage or consequence of leakage.
- The Applicant is conducting a sufficient number of inspections to establish a basis for the Staff to conclude that there is a reasonable assurance that the CLB function(s) of buried systems within the scope of license renewal will be maintained throughout the period of extended operation.

In sum, the Staff has concluded that the aging management program for buried piping and tanks for license renewal of IP2 and IP3 is acceptable, and that there is no merit in the contention's assertion that the LRA does not provide an adequate AMP for in-scope buried piping and tanks that contain radioactive fluid. Staff Testimony (Exhibit NRCR00016) at 22-23.[8]

Further, Mr. Holston presented the Staff's disagreement with the assertion in Contention NYS-5 that there is no adequate program to replace buried SSCs that convey or contain radioactively-contaminated fluids before a leak occurs. In this regard, Mr. Holston stated that the Staff's review found the Applicant's AMP for buried piping and tanks is acceptable and that it meets regulatory requirements. Staff Testimony (Exhibit NRC000016) at 23.

First, 10 C.F.R. § 54.4 does not require that all SSCs that convey or contain radioactively-contaminated fluids be included within the scope of license renewal, or that all the functions of a piping system necessarily be within the scope of license renewal. The Staff's review of the Applicant's LRA determined that the Applicant has properly included within its aging management program the buried piping and tank SSCs that are within the scope of

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[8] Mr. Holston noted that these conclusions pertain only to buried piping and tanks, inasmuch as the LRA and the Applicant's responses to Staff RAIs dated March 28, 2011, show that the Applicant does not have any in-scope underground (i.e., below grade, located in a vault, limited access) piping or tanks (Exhibit NYS000151). Mr. Holston's testimony therefore focuses on "buried" piping and tanks. Staff Testimony (Exhibit NRCR00016) at 23.

license renewal, with proper consideration of the SSCs' functions, as required by 10 C.F.R. § 54.4. *Id.* at 23-24.

Second, the Commission's regulations in 10 C.F.R. § 54.4 and 54.29(a) do not require an applicant to implement an aging management program that will replace a buried SSC before it leaks. The Staff's review of Entergy's LRA determined that its AMP contains acceptable provisions for managing the effects of aging on buried piping and tanks, as required by 10 C.F.R. §§ 54.4 and 54.29(a). *Id.* at 24.

Third, a release or leak from a piping system, whether radiological or non-radiological, would not degrade the ability of a piping system to perform its CLB pressure boundary function unless the leak was very substantial. The Staff's review of the Applicant's LRA determined that the Applicant's AMP for buried piping and tanks provides reasonable assurance that any leakage or release of fluids from buried piping and tanks within the scope of license renewal will not degrade those SSCs' CLB pressure boundary function, as required by 10 C.F.R. § 54.29. *Id.*

Mr. Holston then explained the Staff's conclusion that the Commission's regulations in 10 C.F.R. §§ 54.4, 54.21(a)(3), and 54.29(a) do not require that all SSCs that convey or contain radioactively-contaminated fluids be within the scope of license renewal, or that all the functions of a piping system are necessarily within the scope of license renewal, under 10 C.F.R. § 54.4. In this regard, he pointed out that 10 C.F.R. § 54.4(a) describes the scope of the SSCs that are required to be addressed in the LRA. Further, he observed that 10 C.F.R. § 54.4(b) states, "The <u>intended functions</u> that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section" (emphasis added). Only functions that are required to meet 10 C.F.R. § 54.4(a) are within the scope of license renewal. Staff Testimony (Exhibit NRCR00016) at 24-25.

Mr. Holston explained that "in-scope" systems can have multiple functions. Some of these functions fall within the scoping requirements of 10 C.F.R. § 54.4(a) and thus the SSCs that support these functions must be age-managed in accordance with the rule. Other functions of the system may not fall within the scoping requirements of 10 C.F.R. § 54.4(a), and therefore these functions are not considered to be within the scope of license renewal. Entergy, in its LRA, stated that the following six buried piping systems contain SSCs that are within the scope of 10 C.F.R. § 54.4: city water, service water, auxiliary feedwater, plant drains, fuel oil, and fire protection; and for IP3 only, the following two systems are within the scope of license renewal: safety injection, and security generator. In addition, in subsequent letters, the Applicant stated that the river water and circulating water systems contain buried in-scope piping. *Id.* at 25.

Mr. Holston then addressed the Applicant's statements in LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results," which indicates that the function of these buried piping systems is to provide a pressure boundary. LRA Table 2.0-1 describes this function as, "Provide pressure boundary integrity such that adequate flow and pressure can be delivered. This function includes maintaining structural integrity and preventing leakage or spray for 54.4(a)(2)." This definition of pressure boundary is consistent with the Staff's definition in the Standard Review Plan, NUREG-1800 (Exhibit NYS000195), Table 2.1-4(b), "Typical 'Passive' Component- Intended Functions," and 10 C.F.R. § 54.4(a)(2) which states that in-scope SSCs are "All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section." Therefore, as long as any leakage or spray from the system does not impact the ability of the SSC to deliver flow at an adequate pressure, potential leakage is not a safety consideration for license renewal. Staff Testimony (Exhibit NRCR00016) at 25-26.

Significantly, Mr. Holston observed that although certain leaks have occurred to date at Indian Point, there has not been a failure of buried piping. In this regard, 10 C.F.R. Part 54 establishes safety requirements, rather than the avoidance of environmental impacts -- which, as discussed below, are addressed in regulations governing the operating license (including any renewed license), in 10 C.F.R. Parts 20 and 50. Accordingly, an evaluation of the adequacy of an AMP must focus upon the safety function of the SSC under consideration. *Id.* at 26.

Further, the Commission's regulations in 10 C.F.R. §§ 54.4 and 54.21(a)(3), do not require an applicant to implement an aging management program that will replace a buried SSC before it leaks. In this regard, Mr. Holston observed that 10 C.F.R. § 54.21(a)(3) states:

> For each structure and component identified in paragraph (a)(1) [within the scope of license renewal as delineated 10 C.F.R. § 54.4], demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

Given that the function of the buried piping and tanks is to perform its CLB function as a pressure boundary (i.e., deliver flow between two points at an acceptable flow rate and pressure), as long as the leakage from an in-scope SSC does not impact its ability to perform its pressure boundary function, preventing said leakage is not an intended function for these systems for license renewal. *Id.*

Next, Mr. Holston explained that a leak (whether radioactive or non- radioactive) from a piping system does not degrade the ability of a piping system to perform its CLB pressure boundary function unless the leak is very substantial. In this regard, if a buried pipe or tank were to leak, the intact area of the pipe or tank around the hole or site of leakage can often be demonstrated to meet full structural integrity, notwithstanding the existence of a leak. In other words, unless a leak is substantial, the development of a hole in a pipe or tank would not result in the collapse of the SSC or failure to meet its intended safety function. Accordingly, as long as the piping system meets structural integrity requirements, leaks in piping systems, including buried systems, need not be prevented prior to occurrence. Such leaks are typically discovered and corrected by a licensee before the defect impacts the pipe's pressure boundary function of delivering flow between two points at an acceptable flow rate and pressure. Mr. Holston then provided two examples of leaks that have occurred (a leak in a condensate storage tank return line for IP2, and an internal leak on an IP3 aboveground essential service water line), that did not challenge the structural integrity or the CLB function of the piping; and he stated that he was not aware of a single instance where external corrosion of an in-scope system was so substantial that it resulted in the collapse of the system or the system becoming unable to meet its pressure boundary function as defined in 10 C.F.R. § 54.4(b). *Id.* at 26-27.

Further, Mr. Holston testified that both the Staff and the American Society of Mechanical Engineers (ASME) (an international consensus codes and standards body) have recognized that leakage does not necessarily challenge the intended function of an SSC. For example, the Staff issued Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME Code Class 1, 2, and 3 Piping," to address means to demonstrate structural integrity of piping systems with through-wall defects (Exhibit NRC000024). In addition, the ASME issued ASME Nuclear Code Case 513-3, which addresses temporary acceptance of through-wall flaws in moderate energy (i.e., not exceeding 200°F and 275 psig) Class 2 or 3 piping (Exhibit NRC000025). Further, the ASME Code recognizes that minor leaks can be easily detected prior to challenging the structural integrity of the pressure boundary, as reflected in ASME Nuclear Code Case N-776, which allows an alternative to excavated direct visual examination of piping -- consisting of an inspection for evidence of leakage on ground surfaces in the vicinity of the buried components to validate the structural integrity of the buried piping (Exhibit NRC000026). He therefore concluded that, consistent with these principles, it is acceptable for a license renewal applicant to provide an AMP that focuses on inspections, excavation, and repair of leaks in buried pipes and tanks rather than providing for replacement of the pipe or tank prior to leakage. Staff Testimony (Exhibit NRCR00016) at 27-28.

E. Specific Considerations Regarding the Adequacy of the Applicant's AMP for Buried Piping and Tanks at Indian Point.

Following his discussion of the above general considerations, Mr. Holston provided an evaluation of the Applicant's AMP for buried piping and tanks more specifically. Staff Testimony (Exhibit NRCR00016) at 28-43.

Mr. Holston explained that the Applicant provided its Buried Piping and Tanks inspection program to manage aging effects for buried piping and tanks, as described in LRA Sections A.2.1.5 and B.2.1.6, and RAI responses dated July 27, 2009 (NYS Exhibit 000203), March 28, 2011 (Exhibit NYS000151), July 14, 2011 (Exhibit NYS000152), and July 27, 2011 (Exhibit NYS000153). This AMP is both a preventive action and condition monitoring based program. The program's preventive actions include coatings and wrappings on buried piping. The program's condition monitoring feature includes an extensive number of excavated direct visual inspections of buried piping, which are used to validate the condition of the backfill, coatings and the pipe's external surface. Inspection locations are selected based on risk (i.e., potential for failure and consequence of failure). Inspection results are trended to identify portions of buried piping systems with a history of corrosion problems, which will need to be evaluated for additional inspection, alternate coating, or replacement. The Staff's evaluation of this AMP is set forth in SER (Exhibit NYS000326B) and SER Supplement 1 (Exhibit NYS000160), Section 3.0.3.1.2. In addition, under the NRC's requirements for operating licenses set forth in 10 C.F.R. Part 50, Appendix B, if leaks are discovered, licensees are required to excavate and repair any areas of leakage, and to consider whether any further actions are necessary. Staff Testimony (Exhibit NRCR00016) at 28-29.

With respect to the assertion in Contention NYS-5 that the Applicant's buried piping and tank AMP does not provide an adequate inspection or monitoring program to determine if and when leakage occurs, the Staff determined, first, that 10 C.F.R. Part 54 does not require that in-scope SSCs be managed to prevent leaks; second, that the Applicant's CLB contains acceptable monitoring programs to detect leakage in buried pipes and tanks; and third, the Applicant has provided an acceptable AMP for buried pipes and tanks as part of its LRA for IP2 and IP3. *Id.* at 29.

Mr. Holston explained that under 10 C.F.R. Part 54, an in-scope SSC need not be managed to prevent the occurrence of leaks. Rather, as long as the leakage from an in-scope SSC does not impact its ability to perform its CLB function as a pressure boundary (i.e., deliver flow between two points at an acceptable flow rate and pressure), preventing said leakage is not a requirement for license renewal. Therefore, a buried piping and tank AMP is not required to include an inspection or monitoring program to prevent leaks from occurring. Leak prevention is provided by other means (e.g., protective coatings to prevent external corrosion); if a leak occurs, inspection, monitoring, and corrective action programs are included in the CLB and in a license renewal AMP, so that appropriate actions are taken to detect and repair the leak before it can affect the ability of a SSC to perform its CLB function. *Id.*

Further, other inspection and monitoring programs to detect leakage exist within the Applicant's current licensing basis. In this regard, while 10 C.F.R. Part 54 does not require that in-scope SSCs be age-managed to prevent leaks, regulations governing the Applicant's CLB require that it monitor for leakage. For example, 10 C.F.R. § 20.1501(a)(2) requires that a licensee conduct surveys that may be necessary to evaluate (i) the magnitude and extent of radiation levels, (ii) concentrations or quantities of radioactive material, and (iii) the potential radiological hazards. In addition, under 10 C.F.R. § 20.2203, a licensee is required to report, within 30 days, any radiation exposure or dose, radiation level, or concentration of radioactive materials, that exceeds the limits stated therein. Similarly, 10 C.F.R. § 50.36a ("Technical specifications on effluents from nuclear power reactors") requires that licensees file an annual report which states the quantity of each of the principal radionuclides released to unrestricted areas in liquid and in gaseous effluents during the previous 12 months. Entergy, as holder of the IP2 and IP3 licenses, is required to satisfy these requirements, which would continue to apply to any renewed license. *Id.* at 30.

Mr. Holston then explained the bases for the Staff's conclusion that the Applicant has provided an acceptable AMP for buried pipes and tanks as part of its LRA for IP2 and IP3, based on its review of that AMP. In brief, the Staff concluded that (1) the Applicant's plant-specific operating experience for in-scope buried piping has been properly factored into in the Applicant's proposed AMP, thus providing insights into the need for an appropriate balance of preventive actions and condition monitoring inspections; (2) the AMP appropriately addresses preventive actions as necessary to minimize the potential for external surface corrosion on buried piping and tanks that could lead to leakage; (3) the AMP requires that the selection of inspection locations be risk informed, thus ensuring that the scheduled inspections are conducted in the areas that will have the highest consequence as a result of potential leakage and/or the highest risk of corrosion; and (4) the AMP ensures that the Applicant will conduct a significant and sufficient number of inspections prior to and during the period of extended operation, providing reasonable assurance that the CLB function(s) of the buried systems within the scope of license renewal will be maintained throughout the period of extended operation. *Id.* at 30-31.

With respect to its conclusion that the Applicant's plant-specific operating experience for in-scope buried piping has been properly factored into its AMP, thus providing insights into the need for an appropriate balance of preventive actions and condition monitoring inspections, Mr. Holston explained that the Staff's review of an AMP considers the applicant's discussion of plant-specific operating experience as it relates to damage to coatings and poor backfill quality.

The Staff's review of the plant-specific operating experience at Indian Point as it pertains to in-scope buried pipes and tanks revealed the following:

- In 2007, a buried auxiliary steam line leaked. (It should be noted that this line is not within the scope of license renewal; indeed, none of the buried in-scope piping contains steam.) This failure was determined to be caused by the use of an inappropriate insulation material that allowed water intrusion on the outside surface of the piping leading to corrosion. This incident was discussed in the Applicant's July 27, 2009 letter documenting significant upgrades to its Buried Piping and Tanks Inspection program that are described later in my testimony.

- In 2008, three ten foot segments of IP2 condensate storage tank piping were excavated and the piping was inspected. There were two areas which required coating repairs and two areas where there were minor coating defects. Volumetric inspections confirmed that the piping material still met nominal wall thickness requirements indicating little to no degradation.

- In 2009, an IP2 condensate storage tank return line developed a leak of under 15 gallons per minute. There was no safety significance associated with this event because tank inventory requirements were met throughout the period when the piping was leaking. During inspections of the leak site, it was noted that the coatings had been damaged due to deleterious materials in the backfill which led to sufficient corrosion to penetrate the pipe wall.

Id. at 31-32.

As stated in Entergy's response to RAI 3.0.3.1.2-1, Part 3a (Exhibit NYS000151), the Applicant has conducted other inspections of buried piping that revealed coatings with no defects and no potentially damaging materials in the backfill, as follows:

- In October 2009, 28 feet (two 10-foot sections, and one 8-foot section) of buried city water piping was excavated and the piping was inspected; no coating defects or potentially damaging materials in the backfill were identified.

- In November 2009, 8 feet of buried fire protection was excavated and the piping was inspected; no coating defects or potentially damaging materials in the backfill were identified.

Staff Testimony (Exhibit NRCR00016) at 32.

In summary, the Staff found that the Applicant has excavated and evaluated buried piping at Indian Point on a number of occasions, providing it with plant-specific operating experience information relating to damage to buried piping coatings and the quality of backfill used. Although the Applicant's in-scope buried pipe plant-specific operating experience has revealed locations where coatings have been damaged, the CLB functions of the affected systems were maintained. The Applicant has conducted further inspections which revealed intact coatings and no deleterious materials in the backfill. Most importantly for license renewal purposes, this information has been accounted for in the Applicant's development of its AMP for buried piping and tanks, as discussed below. *Id.*

With respect to the Staff's conclusion that the Applicant's AMP appropriately addresses preventive actions as necessary to minimize the potential for external surface corrosion on buried piping and tanks, Mr. Holston stated that the Staff's review leads it to conclude that the Applicant's AMP is generally consistent with industry standards for preventive actions. For example, the National Association of Corrosion Engineers ("NACE") has issued a standard, NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," which recognizes three preventive actions for buried components, including (a) cathodic protection, (b) protective coatings, and (c) backfill quality such that there are no materials in the backfill that could damage the component's coating (Exhibit NRC000027). Staff Testimony (Exhibit NRCR00016) at 33.

With regard to cathodic protection (the first item listed in NACE SP0169-2007, Exhibit NRC000027), the Applicant does not utilize cathodic protection for its buried piping and tanks at Indian Point , except for its city water lines. As a result of the lack of cathodic protection on most of the in-scope buried components and its plant-specific operating experience at Indian Point, the Applicant has committed (a) to increase the number of inspections that will be conducted prior to entering the period of extended operation and in each of the two ten-year operating periods thereafter, to provide further assurance that coatings and backfill quality meet requirements, and (b) to conduct soil sampling to determine the corrosivity of the soil and further increase inspections if the soil is found to be corrosive. The Applicant's alternative to cathodic protection (i.e., increased piping inspections and soil sampling) thus compensates for its lack of cathodic protection, which is consistent with the Staff's position in GALL Report Revision 2 (Exhibit NYS000147A-D), as discussed below. Staff Testimony (Exhibit NRCR00016) at 33.

With regard to protective coatings (the second item in NACE SP0169-2007, Exhibit NRC000027), LRA Section B.1.6 states, "[p]reventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings." Protective coatings and wrappings were installed on buried piping during construction of Indian Point, in accordance with standard industrial practices; they continue to be installed when replacement or repair activities are conducted, and will be utilized in the period of extended operation. The coatings consist of a coal tar coating covered with a fiber-based wrap saturated with coal tar. This type of coating has been used throughout the nuclear industry to isolate the external surfaces of buried components from the soil environment and is consistent with the recommendations in NACE SP0169 (2007), which lists acceptable coating systems, including the coating system used at Indian Point. Given that the buried piping at Indian Point has been coated in accordance with standard industry practices, and recent inspections have found the coatings to generally be intact (except in locations where deleterious materials in the backfill damaged them), the external surfaces of the buried piping should not degrade unless the coatings are penetrated. Staff Testimony (Exhibit NRCR00016) at 33-34.

In addition, the Applicant has committed to inspect the condition of its buried piping coatings consistent with the recommendations of NACE, which establishes industry standards applicable to all buried piping systems. NACE SP0169-2007, section 5.3.1, states, "These inspections [of coatings] can be conducted wherever the pipeline is excavated or at bell holes made for inspection purposes." Consistent with this recommendation, the Applicant's AMP specifically states that all direct visual examinations of excavated buried SSCs will include a visual examination of coatings. Further, to account for the lack of cathodic protection and previous instances of coating failure due to deleterious materials in the backfill, the Applicant has committed to conduct a significantly larger number of inspections (34) prior to entering the period of extended operation than its AMP had originally provided. Staff Testimony (Exhibit NRCR00016) at 34.

With regard to backfill quality (the third item in NACE SP0169-2007, Exhibit NRC000027), NACE SP0169-2007, section 5.2.3.6, states that, "Care should be taken during backfilling so that rocks and debris do not strike and damage the pipe coating." In this regard, the current Staff position, as cited in GALL Report Revision 2, AMP XI.M41, "Buried and Underground Piping and Tanks," is that backfill quality may be verified by examining the backfill while conducting the inspections. The Applicant's AMP is consistent with the Staff's position related to backfill inspections stated in AMP XI.M41. Given that there have been instances in which backfill damaged protective coatings at the site, the Applicant has increased the quantity of inspections to gain an adequate understanding of the extent to which deleterious materials in its backfill may have damaged protective coatings. The Applicant's action in increasing the number of planned inspections is thus consistent with the Staff's current position in GALL Report, Revision 2 and Final LR-ISG-2011-03 (Exhibit NRC000162). Staff Testimony (Exhibit NRCR00016) at 34-35.

SER Supplement 1 (Exhibit NYS000160), issued in August 2011, documents the Staff's position in regard to coatings and backfill quality at Indian Point; it states:

> Recent inspections found that the backfill did not contain rocks or foreign material that would damage external coatings and the coatings were found to be in good condition. The staff noted that foreign material in backfill caused sufficient damage of the condensate storage tank return line coating such that the line corroded and leaked, and in other instances inspections found coating damage; however, the Applicant's proposed number of inspections meet the current staff position for number of

> inspections for a plant with no cathodic protection and unacceptable backfill quality.

Therefore, it is clear in the LRA and SER that the program includes coatings and backfill quality as key mitigation measures. Staff Testimony (Exhibit NRCR00016) at 35.

In sum, although the Indian Point LRA does not specifically commit to comply with NACE standards, it has addressed the three preventive actions discussed in NACE SP0169-2007 (cathodic protection, protective coatings, and backfill quality) and it has correspondingly increased its number of future inspections due to the lack of cathodic protection and its plant-specific operating experience. Although buried piping at Indian Point does not have cathodic protection as recommended by NACE SP0169-2007, Entergy has accordingly increased its number of inspections of buried pipe and will conduct soil sampling, and it is therefore consistent with the Staff's position in regard to these three preventive actions. *Id.* at 35-36.

Mr. Holston then addressed the Staff's conclusion that the Applicant's AMP requires that the selection of inspection locations be risk informed, thus ensuring that scheduled inspections are conducted in the areas that will have the highest consequence in the event of leakage and/or the highest risk of corrosion. As he stated, the Applicant, in its AMP, committed to classify pipe segments and tanks as having a high, medium or low impact of leakage based on the item's safety class, the hazard posed by fluid contained in the piping, and the impact of leakage on reliable plant operation. The risk ranking will also include a determination of corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. In addition, the AMP provides that the Applicant will establish the inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of its risk assessment. This risk informed inspection approach provides assurance that the scheduled inspections are conducted in the areas that will have the highest consequence due to potential leakage and the highest risk of corrosion, in the event of leakage. *Id.* at 36.

Next, Mr. Holston described the bases for the Staff's conclusion that the Applicant's AMP conducts a sufficient number of inspections so that there is a reasonable assurance that the current licensing basis (CLB) function(s) of the buried systems within the scope of license renewal will be maintained throughout the period of extended operation. In this regard, Mr. Holston observed that New York filed this contention based upon the LRA as it existed at that time; importantly, however, after the contention was filed, the Applicant's Buried Piping and Tanks Inspection program was significantly revised. The first major revision is documented in a letter from Entergy to the Staff, entitled "Questions Regarding Buried Piping Inspections Indian Point Nuclear Generating Unit Nos. 2 & 3," dated July 27, 2009, NL-09-106 (NYS Exhibit 000203). This letter documented a revision to Entergy's inspection program to account for recent plant-specific operating experience described above. This revision incorporated risk-ranking of inspection locations based on the potential consequences of leakage and the potential for corrosion to occur, as recommended by the Electric Power Research Institute ("EPRI"), in "Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks" (1016456, Revision 1) (NYS Exhibit 000167); in revising its AMP, Entergy significantly increased the number of inspections that would occur prior to entering the period of extended operation. The Staff's evaluation of the AMP, as revised in 2009, is documented in the Staff's SER, issued in November 2009 (Exhibit NYS000326A-F). Staff Testimony (Exhibit NRCR00016) at 37.

Subsequent to the issuance of the SER, the Staff issued RAIs related to buried piping and tank programs to all current license renewal applicants, concerning their plans to address recent industry operating experience with buried piping. Thereafter, by letters dated March 28, July 14 and July 27, 2011 (Exhibits NYS000151, NYS000152, and NYS000153), the Applicant further revised its buried piping and tanks AMP, providing more specificity on its planned inspection methods (i.e., excavated direct visual examinations of buried piping), and it committed to conduct additional inspections prior to the period of extended operation and during each of the ten-year periods during the 20-year period of extended operation. The Staff's evaluation of these responses and the Applicant's changes to the program are documented in SER Supplement 1, issued in August 2011 (Exhibit NYS000160). Staff Testimony (Exhibit NRCR00016) at 37-38.

As a result of these changes to its AMP, the Applicant has committed to conduct a total of at least 94 excavated direct visual inspections, as follows: 34 excavated direct visual examinations of in-scope buried piping prior to the period of extended operation, and 30 excavated direct visual examinations of in-scope buried piping during each ten-year period during the 20-year period of extended operation. Each of these 94 inspections will consist of a full circumferential inspection of at least ten feet of pipe. As a result, a minimum of 920 feet of buried piping will be inspected (320 feet prior to the PEO, and 600 feet during the PEO). This number of inspections is sufficient to provide a good understanding of coating and backfill conditions for buried in-scope piping. *Id.* at 38.

In this regard, it should be noted that the Staff developed a revision to the GALL Report, establishing AMP XI.M41 to address plants that do not have cathodic protection for buried piping and tanks, based on industry operating experience and the Staff's review of several LRAs for plants that did not have a cathodic protection system. This revision was addressed in the draft ISG for AMP XI.M41, "Buried and Underground Piping and Tanks" (Draft LR-ISG-2011-03) (Exhibit NRC000019). Following issuance of the draft ISG for public comment, the Staff concluded that the number of inspections it had recommended for two-unit sites in the draft ISG was excessive. Accordingly, as shown in Table 4a of Final LR-ISG-2011-03 (Exhibit NRC000162), the Final ISG recommends for a two-unit site without cathodic protection, that has plant-specific operating experience involving debris in the backfill and coating damage, that 23 inspections be conducted in the final 10 years of the initial period of operation, 30 inspections be conducted in years 40-50 of the PEO, and 38 inspections be conducted in years 50-60 of the PEO (91 in total). The quantity of inspections proposed by the Applicant (a total of 94 inspections),is consistent with the recommendations of the current Staff position as documented in the Final ISG. Staff Testimony (Exhibit NRCR00016) at 38-39.

In addition, the Applicant has committed to conduct soil sampling and testing to determine the soil's corrosivity prior to entering the period of extended operation and once during each ten-year period during the 20-year period of extended operation using industry standard soil testing parameters and corrosivity determination guidance. Soil will be sampled at a minimum of two locations near in-scope piping to determine representative soil conditions for each in-scope system. The soil samples will be analyzed for moisture, pH, chlorides, sulfates, and resistivity. Based on the American Water Works Association Standard C105 (Exhibit NRC000028), these parameters are sufficient to determine the corrosivity of the soil. The Applicant also committed to increase the number of inspections beyond the baseline number by 24 inspections, if the soil samples indicate that the soil is corrosive. This is consistent with the Staff's position in Final ISG-LR-ISG-2011-03 (Exhibit NRC000162). Staff Testimony (Exhibit NRCR00016) at 39.

With respect to buried tanks, the Applicant's eight in-scope buried fuel oil tanks will be inspected once every ten years by conducting thickness measurements on the bottom of the tanks. The bottom of the tank is an area that is highly susceptible to corrosion, and these inspections will provide effective input as to the overall condition of the tank. Conducting the tank inspections once every ten years is consistent with GALL Report AMP XI.M30, "Fuel Oil Chemistry," and in fact, results in more inspections than those recommended in GALL Report AMP XI.M30 (Exhibit NYS000147A-D). Staff Testimony (Exhibit NRCR00016) at 39.

Of the 94 excavated direct visual examinations of buried in-scope piping which the

Applicant has committed to conduct, 53 of its planned inspections will be conducted on systems containing hazardous materials (i.e., materials that are radioactive or deleterious to the environment). In addition, if the soil sample testing demonstrates that the soil environment is corrosive, 16 of the additional 24 inspections that will be conducted (i.e., the 24 inspections that would supplement the planned 94 inspections) will be conducted on systems containing hazardous materials. As discussed above, the Applicant is also risk-ranking the inspection locations based on the potential for corrosion and the consequences of leakage. The committed inspection scope of 53 inspections for systems containing hazardous material, combined with the Applicant's preventive actions, its selection of risk-informed inspection locations in the Applicant's Buried Piping and Tanks Inspection program, and its Corrective Action program, provides reasonable assurance that in-scope buried components which contain radioactive fluids or other hazardous material will meet their intended CLB functions during the period of extended operation. *Id.* at 39-40.

In summary, as a result of plant-specific and industry operating experience, the Applicant has committed to conduct a total of at least 94 inspections, with an additional 24 inspections if the soil is determined to be corrosive, in conjunction with 24 inspections of its eight buried fuel oil storage tanks prior to and during the 20-year period of extended operation. Contrary to New York's assertion, these committed inspections do not represent an inspection program based on "happenstance" and do not leave the detection of leaks to "chance." *Id.* at 40.

Mr. Holston then addressed the assertion in Contention NYS-5 that the LRA and AMP fail to provide an evaluation of the baseline conditions of the buried systems or their welded joints, and do not specify potential corrosion rates, and that such actions must be included in the Applicant's AMP. Mr. Holston stated that the Staff disagreed with New York's assertion, in that it is not necessary for an applicant to provide a complete baseline inspection prior to entering the period of extended operation, or to specify corrosion rates for the piping materials used, to establish the effectiveness of a program to manage the aging of buried components. *Id.* at 40-41.

In support of this determination, Mr. Holston pointed out, first, that Staff guidance does not recommend a baseline inspection or determination of corrosion rates. Thus, neither (a) GALL Report Revision 1 (Exhibit NYS000146A-C), AMP XI.M34, Buried Piping and Tanks Inspection" (the GALL Report Revision that applies to the Applicant's LRA), nor (b) GALL Report Revision 2 (Exhibit NYS000147A-D), AMP XI.M41, "Buried and Underground Piping and Tanks" (issued subsequent to the Applicant's filing of its LRA) provides for a determination of baseline buried piping wall conditions or buried piping corrosion rates. Staff Testimony (Exhibit NRCR00016) at 41.

Second, a determination of baseline buried piping wall conditions and identification of buried piping corrosion rates are not necessary to effectively manage the aging of buried piping and tanks. In this regard, an applicant is not required to provide absolute assurance that a buried pipe or tank will not leak; rather through a combination of preventive actions and condition monitoring, reasonable assurance can be established such "that the effects of aging will be adequately managed so that the intended function(s)" of SSCs within the scope of license renewal "will be maintained consistent with the CLB for the period of extended operation." 10 C.F.R. § 54.21(a)(3). This is consistent with the SRP-LR, NUREG-1800, Revision 1, Section A.1.1, which states, in pertinent part:

> The license renewal process is not intended to demonstrate absolute assurance that structures and components will not fail, but rather that there is *reasonable assurance* that they will perform such that the intended functions are maintained consistent with the current licensing basis during the period of extended operation.

Id., emphasis added. Therefore, it is not necessary to establish, prior to license renewal or during the period of extended operation, a comprehensive as-found wall thickness for buried piping and tanks, to determine a corrosion allowance, or to project when a potential challenge to the CLB pressure boundary function could occur. Other means (as set out in Staff guidance documents such as the GALL Report) have been recognized by the Staff, the Licensing Boards, and the Commission, to establish reasonable assurance that the effects of aging will be adequately managed. In its AMP, the Applicant has committed to conduct 34 excavated direct visual examinations of in-scope buried piping prior to the period of extended operation, thus providing significant information as to the existing condition of buried piping at Indian Point. Further, the Applicant's provision for at least 60 additional excavated direct visual examinations of buried piping (involving at least 600 feet of piping) during the period of extended operation provides additional assurance that significant deleterious conditions affecting the external surfaces of the piping will be detected. The Applicant's plan to conduct a substantial number of direct visual examinations of excavated buried piping prior to the period of extended operation effectively provides a "baseline" of inspections sought by New York (albeit not for the entire length of all buried piping), sufficient to establish a reasonable basis to conclude that buried piping systems within the scope of license renewal will meet their intended CLB function(s). Staff Testimony (Exhibit NRCR00016) at 41-42.

Finally, a baseline inspection is not required, in that the Applicant is required to document any adverse as-found conditions in accordance with 10 C.F.R. Part 50, Appendix B, Criterion XVI ("Corrective Actions"), which requires licensees to identify and document "conditions adverse to quality" and "significant conditions adverse to quality"; further, conditions adverse to quality are required to be corrected, and significant conditions adverse to quality are required to be addressed by determining the cause of the condition and taking corrective actions to preclude repetition. Evidence of the Applicant's effective utilization of its corrective action program as it relates to the Buried Piping and Tanks Inspection program may be seen in its response to the 2008 discovery of degraded coatings on the IP2 CST return line piping, whereby the Applicant replaced the degraded piping, conducted a root cause analysis of the failure, and revised its AMP (by letter dated July 27, 2009) (Exhibit NYS000203) to conduct additional inspections and to risk-rank future inspection locations prior to the period of extended operation. *Id.* at 42-43.

In sum, notwithstanding the absence of a comprehensive baseline inspection or the determination of corrosion rates, the combination of preventive actions, plans for extensive condition monitoring and inspection in conjunction with the use of risk- informed inspection locations, along with the Applicant's Corrective Action program provides reasonable assurance that in-scope buried piping and tanks will meet their intended CLB functions during the period of extended operation. *Id.* at 43.

F. Dr. Duquette's Views Regarding Alleged Deficiencies in the Applicant's AMP for Buried Pipes and Tanks Are Without Merit.

After presenting the Staff's views regarding the adequacy of the Applicant's AMP for buried pipes and tanks, Mr. Holston turned to consider the views expressed by New York's witness, Dr. David Duquette, as set forth in his prefiled written testimony (Exhibit NYS000164), his supporting report (Exhibit NYS000165), and other documents filed by New York in this proceeding regarding Contention NYS-5. Staff Testimony (Exhibit NRCR00016) at 43-71.

In a nutshell, Mr. Holston found that the statements expressed by Dr. Duquette and the other exhibits filed by New York do not warrant a conclusion different from the conclusion that was reached by the Staff. Staff Testimony (Exhibit NRCR00016) at 43-44.

Thus, Mr. Holston disputed Dr. Duquette's assertion, on pages 16-19 and 25 of his testimony, that the Applicant has made insufficient and ambiguous commitments regarding its aging management program for buried piping and tanks. In this regard, the Staff recognized, during its review of the revised AMP prior to the issuance of SER Supplement 1 (Exhibit NYS000160), that the Applicant had not updated its UFSAR Supplement to reflect the number and frequency of piping inspections and soil testing. The Staff therefore issued an RAI requesting that the Applicant revise its UFSAR Supplement to include the number and frequency of piping inspections and soil testing for all buried pipe within the scope of license renewal (Exhibit NYS000200). In its response dated July 14, 2011 and amended by letter dated July 27, 2011 (Exhibits NYS000152 and NYS000153), as documented in SER Supplement 1 (Exhibit NYS000160), the Applicant appropriately revised its UFSAR Supplement, providing details as to the number and frequency of its planned inspections and soil sampling, as follows:

> <u>LRA Section A.2.1.5, Buried Piping and Tanks Inspection Program [IP2]</u>
>
> The Buried Piping and Tanks Inspection Program is a new program that 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, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. 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.
>
> IP2 will perform 20 direct visual inspections of buried piping during the 10 year period prior the PEO. IP2 will perform 14 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years in the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 20 during each 10-year period of the PEO.
>
> <u>LRA Section A.3.1.5, Buried Piping and Tanks Inspection Program [IP3]</u>
>
> The Buried Piping and Tanks Inspection Program is a new program that 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, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are

> inspected when excavated during maintenance. 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.
>
> IP3 will perform 14 direct visual inspections of buried piping during the 10 year period prior the PEO. IP3 will perform 16 direct visual inspections during each 10-year period of the PEO. Soil samples will be taken prior to the PEO and at least once every 10 years into the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of piping inspections will be increased to 22 during each 10-year period of the PEO.

Staff Testimony (Exhibit NRCR00016) at 44-46. In accordance with the provisions of 10 C.F.R. §§ 50.59(c), 50.71(e), and 54.21(d), information that is included in the UFSAR Supplement becomes part of a licensee's CLB, and cannot be revised by the licensee without performing a safety evaluation in accordance with 10 C.F.R. § 50.59 ("Changes, Tests, and Experiments"). The requirements of 10 C.F.R. § 50.59 continue to apply to any renewed license. In addition, pursuant to 10 C.F.R. § 50.59(d)(2), the licensee is required to maintain a record and to inform the Staff of any changes to the UFSAR or UFSAR Supplement made pursuant to 10 C.F.R. § 50.59. Staff Testimony (Exhibit NRCR00016) at 46.

While Dr. Duquette asserts (at page 17) that Entergy's AMP does not explain "what factors Entergy will take into account in performing a risk assessment or to classify its pipe, or how frequently Entergy will inspect pipes according to their priority," that level of detail is not required in an aging management program to satisfy NRC regulatory requirements or to conform to the AMPs set out in the GALL Report. Rather, such details are typically contained in a licensee's inspection plans or procedures for implementation of its aging management programs. Such details are not subject to NRC review and approval prior to license renewal; rather, the Applicant is required to have such details available for Staff verification during an on-site inspection prior to or subsequent to license renewal (under Inspection Procedure 71003 (or

Temporary Instruction (TI) 2516/001) (Exhibit NRC000029), that its license renewal commitments have been implemented. Staff Testimony (Exhibit NRCR00016) at 46.

In this regard, during the week of March 5-9, 2012, the Staff conducted an inspection of the Applicant's progress in satisfying its license renewal commitments, under TI 2516/001. During that inspection, Mr. Holston personally confirmed that the Applicant's Inspection Plan, which is modeled on its corporate program, CEP-UPT-0100, Underground Piping and Tanks Inspection and Monitoring, Revision 0, (NYS Exhibit 000173) contains adequate details for assessing the risk of failure and corrosion for in-scope buried piping and tanks. In addition, Mr. Holston personally confirmed that the Applicant utilized its corporate process to classify its in-scope buried piping and tanks, as documented in site procedure SEP-UIP-IPEC, Underground Components Inspection Plan, Revision 0 (NYS Exhibit 000174). Staff Testimony (Exhibit NRCR00016) at 46-47.

Further, Dr. Duquette's testimony (at page 25) is incorrect, in that Entergy has committed to an "inspection schedule," rather than "creating an unspecified plan that will manage aging." Entergy's AMP, as revised, provides sufficient and unambiguous requirements for the Applicant to (a) ensure that preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings, (b) conduct the specified number of inspections and soil sampling, as stated in its response to the Staff's RAI (Exhibit NYS000152 and NYS000153) and UFSAR Supplement (including an increase in the number of inspections if the soil is found to be corrosive, and (c) as a result of adverse inspection findings, evaluate the need for additional inspections, alternate coatings, or replacement for areas that may be susceptible to corrosion based on its inspection findings. In addition, the Applicant must conduct a safety evaluation under 10 C.F.R. § 50.59, if it chooses to revise the description of the program contained in the UFSAR Supplement. Staff Testimony (Exhibit NRCR00016) at 47.

Dr. Duquette's assertion, at page 25 of his testimony, that "[i]t is not clear how Entergy's response to the RAI squares with the information in Entergy's corporate documents setting inspection priority and scheduling every ten years," is also incorrect. In the event that the NRC issues renewed licenses for IP2 and IP3, the renewed licenses (with their accompanying license conditions and technical specifications) would govern the operation of Indian Point, subject to NRC regulatory requirements, including the requirements in 10 C.F.R. Parts 50 and 54. Any corporate policies that may be adopted by Entergy are not binding on the licensee, for NRC regulatory purposes, unless they are NRC regulatory requirements or are incorporated in the license or the UFSAR. Although Entergy may elect to supplement its license requirements by following its corporate policies at the Indian Point site, those policies would not be enforced by the NRC unless they are incorporated in the current or renewed license or otherwise become NRC requirements. This applies to the three documents discussed by Dr. Duquette at pages 17-26 of his testimony and pages 12-19 of his Report (EN-DC-343, CEP-UPT-0100, and SEP-UIP-IPEC) (respectively, Exhibits NYS000172, NYS000173, and NYS000174). Further, in the event of any conflict between the license or other NRC requirements and Entergy's corporate policies, the license or other NRC requirements would control the plants' operations. Thus, despite any requirements that may exist in Entergy's corporate procedures, IP2 and IP3 must at a minimum meet the requirements contained in their licenses and UFSARs. Procedures that are included in the UFSAR may only be changed in accordance with the provisions of 10 C.F.R. § 50.59. NRC Staff Testimony (Exhibit NRCR00016), at 47-48.

Likewise, there is no merit in Dr. Duquette's assertion, at pages 21-22 of his testimony, that while Entergy has stated that it will conduct 34 pre-PEO inspections at IP2 and IP3, "it is not clear how many inspections, if any, have already taken place that Entergy is counting against this requirement but that were not conducted to the standards to which Entergy's new program would dictate they should be conducted." The Applicant conducted 10 of its committed 34 inspections that are to be conducted in the ten-year period prior to extended operation before it responded to the Staff's RAI on March 28, 2011 (Exhibit NYS000151). These inspections exposed 80 feet of pipe during which the coatings and backfill were inspected. The, method of inspection and parameters being inspected were consistent with both GALL Report AMP XI.M34 and XI.M41. NRC Staff Testimony (Exhibit NRCR00016), at 48.

Similarly, there is no merit in Dr. Duquette's assertion, at pages 9 and 23 of his Report (NYS000165), that the discovery of a leak in 2009 in the CST return line piping (which is the same piping that was inspected in the 2008 CST Inlet - 8" Line 1509 inspection) demonstrates "the failure of [Entergy's] inspection process" and supports the view that Entergy's inspection technique is "clearly inadequate." These statements relate to the leak that occurred on the CST return line piping in 2009, a piping line that had been inspected in 2008. As shown at pages 10 and 11 of Entergy's Corrective Action Report LO-IP3L0-2008-00151 (Exhibit NYS000180), the 2008 inspections were conducted in locations far removed from the as-found leak that occurred in 2009. The Applicant's excavation and inspection of a segment of the CST return line piping in 2008 was not intended to verify the condition of the entire length of CST return line piping – nor are any excavations of buried piping, at any site, intended to verify the condition of the entire line of the piping that is being inspected. Rather, the inspections are intended to determine whether any conditions exist that need to be considered or redressed (either at the inspection site or other locations). An adverse inspection finding would point to the need for further inspections or other actions at the inspection site and/or other locations, while a favorable inspection finding would tend to indicate no reason to take further action. NRC Staff Testimony (Exhibit NRCR00016), at 49.

Dr. Duquette's assertion at pages 16-17 of his testimony and page 14 of his Report (Exhibit NYS000165), that Entergy's AMP offers only unspecified preventive and mitigative measures, and that "Entergy makes no commitment to taking any mitigative measures if problems are found," is also without merit. In this regard, the Staff reached the following conclusions: (a) as described above, the AMP includes provisions for ensuring that the coatings remain intact on buried piping; (b) the inspection portion of the program works in conjunction with various preventive features; (c) the Applicant has committed to trend results from inspections to ensure that areas with a history of corrosion problems are considered for additional inspection, alternate coating, or replacement; and (d) the Applicant's AMP functions in conjunction with the requirements imposed by its current licensing basis – including requirements to ensure that conditions adverse to quality are corrected, under 10 C.F.R. Part 50, Appendix B. *Id.* at 49-50.

First, with respect to the Staff's conclusion that the AMP includes provisions for ensuring that the coatings remain intact on buried piping, the Applicant stated in both its AMP and UFSAR Supplement that external coatings and wrappings will be maintained in accordance with standard industry practice. The Applicant also stated that the quality of backfill, an essential preventive element in protecting the coatings, will be verified during excavated inspections. These are two key preventive measures that are contained in GALL Report AMP XI.M41 (Exhibit NYS000147A-D) and NACE recommendations (Exhibit NRC000027). As long as coatings remain intact, such that water intrusion is prevented, it is very unlikely that external piping corrosion will occur. NRC Staff Testimony (Exhibit NRCR00016), at 50.

Second, with respect to the Staff's conclusion that the inspection portion of the Applicant's program operates in conjunction with various preventive features, the Staff recognizes that inspections, in and of themselves are not a preventive measure (such as coatings, quality backfill and cathodic protection). Nonetheless, inspections work in conjunction with the preventive actions (here, coatings and backfill requirements) to provide information to an applicant on the condition and performance of the existing preventive actions. In this regard, NRC regulations do not require that all buried in-scope piping at a nuclear power plant be cathodically protected, under either an initial or a renewed license; nor is this a requirement or feature in the existing licenses for IP2 and IP3. The Staff developed a draft ISG for GALL Report AMP XI.M41 (Exhibit NRC000019) which was revised and reissued as Final LR-ISG-2011-03 (Exhibit NRC000162), to identify appropriate alternative means to establish reasonable assurance that in-scope buried components will meet their CLB function(s) without cathodic protection. The ISG recommends a higher number of inspections for plants without cathodic protection, to augment the protection afforded by coatings and backfill quality against external corrosion of the piping. The ISG also recommends a further increase in the number of inspections if plant-specific operating experience has revealed prior coating damage or foreign material in the backfill, or if soil conditions are corrosive. NRC Staff Testimony (Exhibit NRCR00016), at 50-51.

Given that plant-specific operating experience at Indian Point includes the discovery of some poor quality backfill resulting in coating damage, which eventually led to piping through-wall penetration, the Staff has evaluated the Applicant's AMP for buried piping and tanks against the higher number of inspections recommended in the ISG for AMP XI.M41 (LR-ISG-2011-03, Exhibit NRC000162). The Staff concluded that the Applicant's proposed number of 94 inspections, with an additional 24 inspections to be performed if the soil is determined to be corrosive, in conjunction with 24 planned inspections of its 8 buried fuel oil storage tanks over the thirty year period starting ten years prior to the period of extended operation, will provide sufficient data to inform the Applicant on the condition of piping coatings and backfill, consistent with the intent of LR-ISG-2011-03 (Exhibit NRC000162). NRC Staff Testimony (Exhibit NRCR00016), at 51.

Third, with respect to the Staff's conclusion that the Applicant has committed to trend results from inspections to ensure that areas with a history of corrosion problems are considered for additional inspection, alternate coating, or replacement, Mr. Holston pointed out that the Applicant has committed to perform trending of adverse buried pipe conditions in its UFSAR Supplement. There, the Applicant stated, "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." Trending provides an additional means of assuring that preventive or corrective actions will be taken in areas with a history of corrosion problems, thus providing additional assurance that the coatings will remain effective in preventing external corrosion of piping. *Id*. at 52.

Fourth, with respect to the Staff's conclusion that the Applicant's AMP functions in conjunction with the requirements imposed by its current licensing basis -- including requirements to ensure that conditions adverse to quality are corrected under 10 C.F.R. Part 50, Appendix B, Mr. Holston pointed out that if renewed licenses are issued for IP2 and IP3, all aspects of the licensee's current licensing basis will remain in effect during the period of extended operation. Therefore, the provisions of 10 C.F.R. Part 50, Appendix B, Criterion XVI, Corrective Actions, will apply -- which require that conditions adverse to quality (e.g., coating damage, external corrosion of buried piping) are corrected. This consideration is factored into the Staff's evaluation of each aging management program. Thus, GALL Report program element seven, "corrective actions," is addressed for every program submitted by a license renewal applicant. In addition, NRC Staff personnel in the four NRC regional offices periodically conduct "Problem Identification and Resolution" inspections at all nuclear plants that look for gaps in corrective action program performance. Given that correcting conditions adverse to quality is a current licensing basis requirement and there are periodic NRC inspections of the corrective action program, there is reasonable assurance that adverse buried piping and tank inspection results will be corrected. Accordingly, if the external surfaces of the piping, coatings, and backfill quality are found to not meet the standards imposed by the plants' CLB, there is reasonable assurance that they will be restored to meet existing license requirements. *Id.* at 52-53.

Next, Mr. Holston addressed Dr. Duquette's assertion, at pages 18-19 of his testimony, that the buried piping AMP "contains very few actual commitments," in that the AMP does not identify the "proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls" referred to in the AMP, and therefore "it is not possible to determine at this time whether the inspection program will meet the requirements for an adequate AMP." These assertions are incorrect. Although LRA Section B.1.6 does not provide explicit details on the Applicant's acceptance criteria, corrective actions, and administrative controls, the AMP cites GALL Report AMP XI.M34, which states that:

> Any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures. <u>The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.</u> The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

Id., emphasis added. By committing to adhere to existing IP2/IP3 corrective action programs, procedures and administrative controls – which were established under the current licenses in accordance with 10 C.F.R. Part 50, Appendix B – the AMP satisfies GALL Report AMP XI.M34 and provides sufficient information to support a conclusion that the corrective action program is adequate. NRC Staff Testimony (Exhibit NRCR00016), at 53.

In this regard, 10 C.F.R. Part 50, Appendix B, Criterion III ("Design Control"), requires that:

> Measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure

> that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

As at other nuclear power plants, the Indian Point specifications, drawings, procedures, and instructions establish the basis for the plants' acceptance criteria. As discussed above, under the IP2/IP3 licenses, conditions adverse to quality are required to be promptly identified and corrected. The identification of a condition adverse to quality is accomplished by comparing the as-found condition of the piping and coatings to the acceptance criteria, and to determine if the SSC is either fit for duty until a subsequent inspection, repair the SSC, or replace the affected item. Thus, the correction is accomplished by repair, replacement or modification in accordance with the design controls as described in 10 C.F.R. Part 50, Appendix B, Criterion III. Given that these requirements reside in the existing CLB, there is no need to repeat them in an aging management program. Thus, the regulatory requirement in Appendix B effectively provides for a comparison of the as-found piping to the plant's design criteria. *Id.* at 53-54.

The Staff's evaluation of Entergy's discussion of operating experience, discussed in SER Section 3.3.2.2.8 (Exhibit NYS000326D), at page 3-373, took note of Entergy's statement that leaks involving non-safety related piping, outside the scope of license renewal (i.e., the auxiliary steam line), had been addressed in two condition reports – and apart from those leaks, since 2000, "no other buried piping repair or replacement was identified during its review of operating experience." (As discussed above, in 2009, the year after Entergy made this statement, a further leak was discovered in the CST return line, which was then repaired.) *Id.* at 54.

In sum, the Staff has concluded that the description of the Applicant's corrective action program in its buried piping and tank AMP is adequate because (a) it is in accordance with the Staff's position as promulgated in GALL Report AMP XI.M34, (b) the current licensing basis 10 C.F.R. Part 50, Appendix B program provides adequate controls for acceptance criteria and repairs, and (c) the Staff has conducted routine inspections of the corrective action program under the existing licenses, and will continue to conduct routine inspections of the corrective action program during the period of extended operation, thus providing verification of the adequacy of the corrective action program. *Id.* at 54-55.

Mr. Holston also disputed Dr. Duquette's assertion, at page 18 of his testimony, that the Applicant's AMP is only "conceptual" in nature. In this regard, Mr. Holston pointed out that the Applicant will conduct excavated direct visual inspections of its buried piping as stated in Exhibit NYS000160. Each inspection will consist of exposing the complete circumference of ten feet of pipe. This commitment clearly describes the monitoring that will be conducted as part of the program. Similarly, the Applicant has provided specific details regarding its commitments to conduct buried tank inspections and soil sampling. *Id. at 55.*

Dr. Duquette also asserted, at page 19 of his testimony, that if the Applicant's "internal documents [i.e., Entergy's corporate buried pipe procedures] are not included in the commitment from Entergy or made a part of the LRA," they are "subject to modification by Entergy without NRC approval and would not be obligations imposed on Entergy by a renewed license." While that statement may be correct, in general, it is incomplete. Thus, Mr. Holston agreed that, to the extent Entergy's corporate procedures are not incorporated in the plants' operating licenses or the updated UFSARs, they are not binding upon the licensee. Here, however, that general assertion is of no concern, in that essential aspects of the corporate program including preventive measures to mitigate corrosion, trending of inspection results, quantity and frequency of inspections, quantity and frequency of soil sampling, and expansion of inspection scope should the soil be demonstrated to be corrosive, are all included in the Applicant's UFSARs. Further, changes to procedures described in the UFSAR can only be made in accordance with the 10 C.F.R. § 50.59 process. NRC Staff Testimony (Exhibit NRCR00016), at 55-56.

Dr. Duquette further asserted, at page 20 of his testimony, that "[i]n the risk-ranking section, an assemblage of as-built-drawings is required. It is not clear if such a set actually exists or if it was or will be provided for review in the LRA licensing process." That complaint is without merit. Under the CLB for IP2 and IP3, the Applicant is required to maintain plant drawings, to document any adverse as-found conditions and to update its drawings to reflect such conditions, pursuant to 10 C.F.R. Part 50, Appendix B, Criterion V ("Instructions, Procedures, and Drawings"). This requirement will continue to apply during the period of extended operation; there is no need to duplicate this requirement in the LRA or AMP. *Id.* at 56.

G. Dr. Duquette's Views Regarding the Inadequacy of an AMP for Buried Pipes and Tanks that Lacks Cathodic Protection Are Without Merit.

Fundamentally, Dr. Duquette's views regarding the adequacy of the Applicant's AMP for buried pipes and tanks appears to rest, in large part, upon his assertion, at page 25 of his testimony, that Entergy's buried piping AMP is inadequate because it does not require cathodic protection to manage aging pipes. That view is inconsistent with NRC regulatory guidance, which recognizes that an AMP can provide acceptable alternatives to cathodic protection.

As Mr. Holston explained, the GALL Report recognizes that an adequate AMP can be developed in the absence of cathodic protection. In this regard, the Staff reached the following four conclusions: (a) neither 10 C.F.R. Part 50 nor 10 C.F.R. Part 54 require the use of a cathodic protection system – either during the initial license period or the period of extended operation; (b) an applicant can develop an aging management program which is consistent with GALL Report AMP XI.M34 (Exhibit NYS000146A-C) or AMP XI.M41 (NYS000147A-D) under LR-ISG-2011-03 (Exhibit NRC000162) without providing cathodic protection; (c) Indian Point's AMP is consistent with the number of inspections of buried pipe in the Staff's ISG for AMP XI.M41 concerning buried piping and tanks without cathodic protection; and (d) no significant failures of in-scope piping systems have occurred at Indian Point that would warrant imposition of a requirement to install cathodic protection. NRC Staff Testimony (Exhibit NRCR00016), at 56-57

First, as Mr. Holston observes (*id*. at 56), 10 C.F.R. Part 50 and 10 C.F.R. Part 54 do not require the use of a cathodic protection system, either during the initial license period or the period of extended operation. Indeed, nowhere in 10 C.F.R. Part 50 or 10 C.F.R. Part 54 is there any stated requirement for the use of a cathodic protection system – either during the initial license period or the period of extended operation. *See id.* at 57.

Second, the Staff recognizes that an applicant can develop an aging management program which is consistent with GALL Report AMP XI.M34 (Exhibit NYS000146A-C) or AMP XI.M41 (NYS000147A-D) under LR-ISG-2011-03 (Exhibit NRC000162) without providing cathodic protection. Thus, nowhere in GALL Report AMP XI.M34 is there any stated recommendation for the use of a cathodic protection system. The ISG for AMP XI.M41 (Final LR-ISG-2011-03) (Exhibit NRC000162), like the draft ISG (Exhibit NRC000019), addresses the recommendations for an AMP for buried piping and tanks without cathodic protection, and does not require the installation of cathodic protection for all such buried piping and tanks that lack cathodic protection. Reasonable assurance can be established that in-scope buried components will meet their CLB function(s) in the absence of cathodic protection given implementation of the alternative recommendations contained in the Final ISG. NRC Staff Testimony (Exhibit NRCR00016), at 57.

Third, Mr. Holston explained the Staff's conclusion that Indian Point's AMP is consistent with the number of inspections of buried pipe in the Staff's Final ISG for AMP XI.M41, concerning buried piping and tanks that lack cathodic protection (Exhibit NRC000162). As stated by Mr. Holston – who, as the author of the ISG (page 14, *supra*), is intimately familiar with it – the explicit language of the ISG recognizes that cathodic protection is not available at all plants, and that other measures may be taken to protect buried piping and tanks without cathodic protection and still establish a reasonable assurance that in-scope buried components will meet their CLB functions. Thus, the Discussion section of the ISG on buried piping and tanks states:

> Table 4a, Inspections of Buried Pipe, was revised to reflect the recommended number of inspections <u>when cathodic protection will not be provided during the period of extended operation for systems or portions of systems within the scope of license renewal</u>. The basis for the number of inspections in the original issuance of AMP XI.M41 was the availability of cathodic protection, quality of backfill, and the presence of coatings. <u>For plants without cathodic protection in use during the period of extended operation</u>, the factors that form the basis for the number of inspections were changed to reflect additional emphasis on plant-specific OE related to backfill, coatings, inspection results, emergent conditions, and soil sampling. These factors were established because, absent cathodic protection, the coatings are the only barrier to corrosion. The staff recognized that non-corrosive soil will result in lower corrosion rates, but not necessarily eliminate corrosion. Backfill that contains objects that can damage the coating can result in a direct challenge to the integrity of the piping system. The inspection quantities were increased because without the preventive action of a cathodic protection system and the ability to trend cathodic protection currents, an indicator of coating degradation, increased inspections were necessary to provide reasonable assurance that the components will meet their current licensing basis (CLB) functions throughout the period of extended operation. These inspection quantities are the minimum recommended and could possibly need to be higher based on factors such as the plant-specific soil conditions, ground-to-structure potentials and OE.

NRC Staff Testimony (Exhibit NRCR00016) at 58, *quoting* LR-ISG-2011-03 (Exhibit NRC000162), at page 3*;* emphasis added.

As recommended in the Final ISG IP2 and IP3 would fall within inspection category F. Category F would recommend a total of 91 inspections for a two unit site during years 30 – 60 of the plants' operation. The comparable inspection quantities for Indian Point are 94 (for soil that is non-corrosive) and 118 (for soil that is corrosive). Thus, the number of inspections at Indian Point for Category F soils exceeds the number of inspections recommended in LR-ISG-2011-

03, and is sufficient to understand the condition of the buried piping at Indian Point. NRC Staff Testimony (Exhibit NRCR00016), at 58-59.

Dr. Duquette states, at page 24 of his Report, that "[f]or carbon steel components[,] NUREG-1801 Section XI.M41 specifies that buried piping should be coated and cathodically protected." Those statements require clarification. First, the GALL Report, AMP XI.M41 is a set of recommendations, not requirements. Applicants can propose alternatives to the AMP as long as those alternatives are sufficient to establish a reasonable assurance that the buried component's CLB functions will be met. Second, as documented in the ISG, soil sampling and augmented inspections constitute an acceptable <u>alternative</u> to installing cathodic protection. In this regard, although the Staff did not evaluate Entergy's AMP for conformance to GALL Report Revision 2, the Staff nonetheless requested additional information from the Applicant in RAIs 3.0.3.1.2-1, 3.0.3.1.2-2, and 3.0.3.1.2-3, (Exhibits NYS000199 and NYS000200) to enable the Staff to consider the adequacy of the AMP as compared to the recommendations in GALL Report Rev. 2, AMP XI.M41. Based on its review of the revised buried piping and tank's AMP, the Staff determined that Entergy's AMP for buried piping and tanks far exceeds the recommendations in GALL AMP XI.M34 (Exhibit NYS000146A-C), and would satisfy AMP XI.M41 in GALL Report Revision 2, given Entergy's provision for a substantial number of additional inspections (i.e., 94 excavated direct visual inspections of ten feet of buried piping versus the recommended two inspections in GALL AMP XI.M34), the inclusion of soil testing, and the augmented inspection requirements if the soil is found to be corrosive. NRC Staff Testimony (Exhibit NRCR00016), at 59-60.

Fourth, the Staff's conclusion that no significant failures of in-scope piping systems have occurred at Indian Point that would warrant imposition of a requirement to install cathodic protection, is based upon the Staff's review of the plant-specific operating experience at Indian Point. That review found that no significant failures (i.e., failure to provide pressure boundary integrity such that adequate flow and pressure cannot be delivered) of in-scope buried piping have occurred. Apart from some minor coating degradation, the only significant degradation of in-scope piping at Indian Point was associated with the leakage from the CST return line in February 2009, as documented in Entergy's Root Cause Analysis ("RCA") Report, CP-IP2-2009-00666 (Exhibit NYS000179). Although the CST was initially declared inoperable (an appropriate initial conservative position until backup analyses could be conducted), page 31 of the RCA Report documents that structural integrity requirements for the piping were met, the through-wall leaks could not lead to draining of the CST below minimum inventory requirements, and the loss of inventory returned to the CST if the auxiliary feedwater pumps had been required to operate would have been too small to challenge the minimum inventory requirements in the tank. Thus, the in-scope function of the CST return line was met, and therefore, the CST return line leak did not constitute a "failure". *Id.* at 60-61.

This conclusion is supported by the Structural Integrity Associates ("SIA") Report, "Analysis of 8" Condensate Water Storage Tank Return Line CD-183 Final Report" (May 15, 2009) (Exhibit NYS000175). Thus, the SIA Report states, at page 59, that "[t]he surfaces around the pits on the straight pipe had no evidence at all of corrosion and the original mill scale (high temperature iron oxide) was intact, indicating that where the coating remains intact the pipe surfaces are adequately protected against corrosion." In addition, the SIA Report states:

> Since a relatively large surface area of the sample has no evidence of corrosion, exposure to leaking water or to water-saturated soil apparently did not have a significant effect on the protectiveness of the coating on the pipe. Rather, the large number of observed pits is more likely related to the occurrence of coating damage that occurred during installation; not to gradual or long term coating degradation that could potentially [occur] as a result of exposure to leaking water or water-saturated soil.

These statements in the SIA Report, along with the map of external corrosion on the degraded piping shown in Figure 15 (page 22), and the fact that the piping met structural integrity requirements, support a conclusion that damage caused by backfill materials impacting the pipe coatings is most likely limited to discrete locations and would result in localized damage only, such that the unaffected portions of the piping that have intact coatings provide adequate structural reinforcement to the degraded areas and the pipe's intended function would be met. NRC Staff Testimony (Exhibit NRCR00016), at 61

Nor is Dr. Duquette correct in asserting, at pages 22 and 26 of his testimony, that the soil conditions at Indian Point warrant the need for cathodic protection, as shown by previous corrosion of the discharge canal sheet piling system at the site. Leaving aside the question of whether river water and sediments in a brackish tidal estuary like the Hudson River is representative of soils at the Indian Point site, the soil conditions at Indian Point have not been found to be so severe as to warrant cathodic protection. This is demonstrated in Entergy's Engineering Report No. IP-RPT-09-00011 (Exhibit NYS000178), "Corrosion/Cathodic Protection Field Survey and Assessment of Underground Structures at Indian Point Energy Center Units 2 and 3, during October 2008," Table, Corrosion Field Survey Data and Tables," page 25, which reported that four soil resistivity readings exceeded 28,725 ohm-cm, and two others were 8043 and 11,490 ohm-cm. As stated on page 7 of Engineering Report No. IP-RPT-09-00011 (Exhibit NYS000178), and as generally accepted in the industry, a reading of 2000 to 10,000 ohm-cm is moderately corrosive and a reading of 10,000 – 30,000 ohm-cm is mildly corrosive. As discussed above, additional periodic soil samples will be taken in the vicinity of in-scope buried piping, and will be followed by further augmented pipe inspections if the soil is demonstrated to be corrosive. In addition, Entergy's Corrective Action Report CR-IP2-2005-03902 (Exhibit NYS000177), page 5 of 6, states, "There are no radiological, nuclear [or] industrial safety issues associated with the lack of Cathodic Protection [for specified buried piping systems]." NRC Staff Testimony (Exhibit NRCR00016), at 61-62.

Similarly, there is no basis for Dr. Duquette's assertion, at page 22 of his testimony and page 19 of his Report, that the inactive condition of the IP2/IP3 cathodic protection system resulted from "latent organization weakness in that the risk associated with the lack of a CP system was not clearly understood by personnel approving resource allocation to complete the modification process." In support of this assertion, Dr. Duquette cites an observation that was made in 2005. However, a "latent organizational weakness" identified in 2005 if it existed, is immaterial to decision-making six years later, given the current knowledge of in-scope buried piping conditions. The current knowledge of piping conditions is based on over 36 years of the piping's exposure to the soil environment, excavated direct visual inspections of 80 feet of pipe, excavations for the single in-scope leak that occurred, and the lack of any history of loss of CLB functions due to corrosion. Based on this information, there is no compelling reason why installation of a cathodic protection system is required to adequately manage the aging of buried piping and tanks for the IP2/IP3 LRA. *Id.* at 62-63.

Similarly, there is no basis for Dr. Duquette's assertion, at pages 19-20 of his Report, that, the need for cathodic protection at IP2/IP3 is demonstrated by Entergy's Condition Report IP2-2005-03902 (Exhibit NYS00177), Sheet 1 of 6, which indicated that the Institute of Nuclear Power Operations (INPO) had completed an investigation of the cathodic protection systems at Indian Point, and concluded that "[t]he lack of a functioning cathodic protection system in severe environmental conditions leaves piping and structures susceptible to corrosion-induced failures." The statement cited by Dr. Duquette relates to "severe environmental conditions." As discussed above, the in-scope buried piping at Indian Point is not subject to "severe environmental conditions"; rather, the actual soil conditions are mildly to moderately corrosive. Further, the cited discussion refers to INPO's identification of an Area for Improvement ("AFI") at Indian Point; Dr. Duquette fails to note that the next sentence of Entergy's report recites INPO's observation that "[a]n analysis has not been performed to identify the effects on system operation or if compensatory measures are needed." (Exhibit NYS000177, sheet 1 of 6). Thus, the Condition Report does not support Dr. Duquette's conclusion that INPO identified a need for cathodic protection to avert failure of a system, or that other measures could not be provided in lieu of cathodic protection. Also, in the context of the INPO data discussed here, the term "corrosion-induced failures" refers to leakage from the piping; this does not correspond to the loss of a 10 C.F.R. § 54.4(b) intended function. For buried piping, as discussed above and as indicated in NUREG-1800, Revision 2, Table 2.1-4(b) (Typical "Passive" Component- Intended Functions) (Exhibit NYS000161), the piping's intended function is a pressure boundary function, i.e., to provide a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered to another plant system. As demonstrated by the condensate storage tank return line degradation, although leakage occurred, the leakage did not result in a "corrosion-induced failure" of the piping system. NRC Staff Testimony (Exhibit NRCR00016), at 63-64.

Entergy's Condition Report CR-IP2-2005-03907 (Exhibit NYS000177) similarly does not support Dr. Duquette's view that cathodic protection must be provided for buried piping and tanks at Indian Point. That report, at Sheet 6 of 6, states: "Develop an action plan for the IPEC Cathodic Protection System. Assign additional corrective actions for the action plan actions if necessary." At the same time, however, the Condition Report states (at Sheet 5 of 6), that "[t]here are no radiological, nuclear of [sic] industrial safety issues associated with the lack of Cathodic Protection." In sum, the document discusses the existing condition of the cathodic protection system, but neither requires cathodic protection nor states that absent cathodic protection, the aging of buried pipes will be inadequately managed. This approach is consistent with GALL Report, Revision 2, AMP XI.M41 (Exhibit NYS000147A-D), and the ISG discussed above (Exhibit NRC000162). Thus, while AMP XI.M41 recommends that cathodic protection be utilized, it recognizes that CP need not be provided as part of an AMP as long as acceptable alternatives are provided. Although cathodic protection may be viewed as a "best practices for corrosion prevention," cathodic protection is not necessarily required to properly manage the aging of buried in-scope piping and tanks, where (as here) acceptable alternatives have been provided. NRC Staff Testimony (Exhibit NRCR00016), at 64.

There is likewise no merit in Dr. Duquette's assertion, at pages 16 and 24 of his testimony, that Revision 1 of the GALL Report, cited in Entergy's AMP for buried piping and tanks, has been "superseded" or is "outdated." Entergy, committed, in its original LRA (submitted in April 2007), to meet GALL Report Revision 1, AMP XI.M34, issued in 2005 (Exhibit NYS000146A-C); its AMP for buried piping and tanks, without cathodic protection, was consistent with the 2005 version of the GALL Report. The guidance provided in GALL Report Revision 1 continues to apply to plants whose license renewal applications were docketed prior to issuance of GALL Report Revision 2, in December 2010 (Exhibit NYS000147A-D). Nonetheless, as discussed above, Entergy subsequently revised its AMP for buried piping and tanks, resulting in the Staff's conclusion that the revised program provides reasonable assurance that the in-scope buried piping and tanks would meet their CLB function(s) during the period of extended operation. NRC Staff Testimony (Exhibit NRCR00016), at 64-65.

There is also no merit in Dr. Duquette's assertion, at pages 24-25 of his testimony, that because Entergy has designated all radioactive fluid containing piping systems "high priority" in CEP-UPT-0100, for which inspections are to be done every ten years, "such a long period between inspections is questionable, especially for the highest risk piping systems." Here, 24 additional inspections will be performed in the remaining years prior to license renewal; 30 inspections will be conducted in the next 10-year period; and 30 inspections will be conducted in the final 10-year period. It is therefore reasonable to expect that long periods of time would not occur between inspections. In fact, during the March 2012 inspection of the Applicant's license renewal commitments, Mr. Holston personally observed that buried piping and tank inspections are scheduled to occur over multiple years during the ten-year period prior to the period of extended operation, not after a ten-year interval has elapsed (page 65, Appendix G) (NYS Exhibit 000174). Nonetheless, it should be noted that a ten-year inspection interval is consistent with the inspection interval specified in GALL Report AMP XI.M41 (Exhibit NYS000147A-D). NRC Staff Testimony (Exhibit NRCR00016), at 65.

Dr. Duquette also asserts, at pages 24-25 of his testimony, that it "is not clear" how Entergy's RAI response, stating it would perform more than 80 inspections, "squares with the information in Entergy's corporate documents setting inspection priority and scheduling every ten years"; that "Entergy has not committed" to any inspection schedule either "in the AMP or in a regulatory commitment"; and that "the only thing Entergy has committed to in its AMP is creat[ion] of an unspecified plan . . . [to] manage aging." This assertion is also without merit. The Staff's review leads it to find that the AMP is not an "unspecified plan." Rather, the Applicant has committed to the number of inspections, soil testing (which could lead to further inspections), and trending of inspection results in its UFSAR or UFSAR Supplement. The Applicant's commitments conform to NRC regulatory guidance, including the periodicity of buried piping and tank inspections contained in GALL Report AMPs XI.M34 and XI.M41 and LR-ISG-2011-03 (i.e., inspections are specified to occur during discrete ten year inspection intervals starting ten years prior to the period of extended operation), and are acceptable (Exhibits NYS000146A-C and NRC000162). NRC Staff Testimony (Exhibit NRCR00016), at 66.

Similarly, there is no merit in Dr. Duquette's assertion, at page 26 of his testimony, that "cathodic protection is important at Indian Point" because (a) "Entergy's inspections indicate that in at least one location, piping degradation has reduced pipe wall thickness by 85% (that is, to only 15%)," (b) "IPEC has experienced through-wall failures in the condensate storage line" and (c) "Entergy's own consultants have issued a report indicating that the soils are corrosive."

First, Dr. Duquette's report, page 18, footnote 33, refers to Structural Integrity Analysis's ("SIA") Report 0900235401R0, which is referenced in footnote 1 of SIA's Report 0900235.402 R0 (Exhibit NYS000175). As described in SIA Report 0900235.402, SIA's other report (Report 0900235401R0) contains a summary of a guided wave examination conducted on the AFW suction line (a guided wave examination is a volumetric ultrasound-based screening tool used to identify potential areas of degradation). SIA Report 0900235.402 (Exhibit NYS000175) states, at page 6, that, "After identifying the leak location and adjacent areas of significant wall loss, Indian Point excavated the area and in accordance with their Technical Specifications replaced the leaking section of the piping." As further stated on page 6 of SIA Report 0900235.402 (Exhibit NYS000175), the areas found to have significant pipe wall loss were adjacent to the site of the leak in the AFW suction line. Therefore, statements made by Dr. Duquette in (a) and (b) above refer to a single area of degraded piping. There was a leak in an out-of-scope auxiliary steam line, referred to in Dr. Duquette's Report (Exhibit NYS000175) at page 9 -- which the Staff also considered in assessing whether the Applicant's planned number of inspections is sufficient. In addition, as noted in Dr. Duquette's Report (at page 9), there were two leaks associated with the spent fuel pools at IP1 and IP2 -- but these leaks do not support the need for cathodic protection, in that (a) the components do not consist of buried piping or tanks, (b) they did not leak due to external corrosion, and (c) are not within the scope of the AMP for buried piping and tanks. NRC Staff Testimony (Exhibit NRCR00016), at 66-67.

Second, the condensate return line did not experience a through-wall failure. Although the line developed a leak, subsequent evaluations determined that its current licensing basis function could be met despite the leak; therefore, as discussed above, the term "failure" is not appropriate. *Id.* at 67.

Third, while Dr. Duquette states that Entergy's consultants have indicated the soil is "corrosive," this statement does not indicate the degree of corrosivity that has been reported.

Thus, elsewhere in his testimony and report (page 21), he recognizes that the soil was found to be "moderately corrosive" in one location, while the majority of the soil readings found only "mildly" corrosive conditions. The finding of mildly corrosive conditions is reinforced by the considerable length of in-service time for the CST return line prior to the development of a leak, and by the results of the other inspections conducted to date. *Id.* at 67-68.

New York asserts, in its Statement of Position, that the Staff has "acknowledged" that "[t]he buried pipe degradation conditions at… Indian Point . . . illustrate that Plants do not fully know what they have in the scope and condition of buried piping." New York Statement of Position (NYS000163) at 19, citing Exhibit NYS000196. This assertion is baseless. In making this statement, New York quotes part of an E-mail message (Exhibit NYS000196) sent by a member of the NRC Region I Staff (Harold Gray) to another Region I Staff member (Richard Conte) in April 2010, regarding the discovery of leaks at several nuclear power plants. New York's Statement of Position, however, omits certain words from the message, which are important to put the quoted words in proper context. Specifically, the message stated, "The buried pipe degradation conditions <u>at Oyster Creek, Indian Point and Salem, while not having serious operability or safety consequences</u>, collectively illustrate that Plants do not fully know what they have in the scope and condition of buried piping." Exhibit NYS000196; emphasis added. The E- mail thus describes the writer's concern over a potential industry-wide problem, as well as his view that the concern did not raise "serious operability or safety" implications. As is evident from a reading of the E-mail, the writer was proposing that the Staff pursue a generic communication with the industry to obtain additional information related to buried piping, to allow the Staff to give further consideration to this issue. Ultimately, the Staff, acting under the direction of the Commission, determined that the appropriate approach to address industry-wide buried piping issues was to continue to monitor the NEI Initiative, NEI-09-14 (Exhibit NYS000168), which called upon all nuclear power plant licensees to "Risk Rank buried piping segments by December 31, 2010" and "[b]y June 30, 2011, develop an inspection plan to provide reasonable assurance of integrity of buried piping." As stated above, the Commission issued an SRM regarding this NEI initiative, in which it directed the Staff to make clear that "while the agency will continue to monitor the industry's voluntary initiatives, no changes to the regulatory framework are currently being contemplated." NRC Staff Testimony (Exhibit NRCR00016), at 68-69.

New York also states that in an internal E-mail message (NYS000197), Entergy admitted it has "no existing technology that could determine the 'health' of our buried piping without the use of excavation" (Statement of Position (NYS000163) at 19, citing NYS000197), and that this supports Dr. Duquette's view that the AMP is inadequate. This claim is also without merit. The cited statement quotes part of an internal Entergy E-mail message dated August 12, 2008 (Exhibit NYS000197). At the time the E-mail message was written, no excavated direct visual inspections had been conducted as part of the AMP, and inspections of these types were one of the few tools available to the industry to determine the condition of its buried piping. Subsequently, an improved understanding of site conditions was obtained through the use of excavated inspections. As discussed above, excavated direct visual inspections commenced in 2009 at multiple locations, and the Applicant has committed to conduct an extensive number of inspections prior to and during the period of extended operation. The Applicant's operating experience to date, along with its buried piping and tanks inspection program, provide a good understanding of the condition of buried piping for the IP2/IP3 LRA. NRC Staff Testimony (Exhibit NRCR00016), at 69.

The Staff also disagrees with New York's assertion, at page 44 of its Statement of Position (Exhibit NYS000163), that the Applicant's AMP cannot be found to be adequate, "absent a thorough inspection, essentially excavation, of virtually all relevant buried pipes at the Indian Point site." In support of this assertion, New York asserts that proper oversight procedures may not have been implemented during construction when coatings were applied, that Entergy did not know improper backfill had been used during construction, and that Entergy did not make available the engineering report supporting the original plant owner's decision to limit the installation of cathodic protection to certain systems. Exhibit NYS000163, at 44-45. These assertions, even if correct, fail to take account of other information that supports a determination that the Applicant's AMP for buried piping and tanks is acceptable. Thus, inspections of 30 feet of the CST return line, 28 feet of city water piping, and 8 feet of fire protection piping (a portion of the 34 inspections that will be conducted prior to the period of extended operation), found one instance of adverse conditions (involving the CST return line); and inspections of an additional 70 feet of piping did not reveal adverse backfill conditions or coating degradation that resulted in external surface corrosion that challenged the nominal wall thickness of the piping. Given the number of additional inspections that will be conducted prior to and during the period of extended operation, as well as the extensive amount of soil sampling and testing that will be conducted, there is no reason to require an "inspection, essentially excavation, of virtually all relevant buried pipes at the Indian Point site" before the acceptability of Entergy's AMP can be assessed. NRC Staff Testimony (Exhibit NRCR00016), at 69-70.

Further, there is no regulatory significance to New York's assertion, at page 19 of its Statement of Position (Exhibit NYS000163), that Entergy's buried piping AMP, as revised, fails to meet "the industry standard of care established by [NEI and EPRI] initiatives" (Exhibits NYS000167, NYS000168 and NYS000169). Simply stated, the NRC does not require its licensees to satisfy industry guidelines or recommendations, unless those recommendations have been adopted as regulatory or license requirements; similarly, the Staff does not evaluate the adequacy of an applicant's AMP against the recommendations of industry groups, and the Staff cannot speak on behalf of those groups. Nonetheless, in the Staff's assessment of this matter, it was apparent that the Applicant's AMP addresses some or all of those NEI and EPRI recommendations. For example, as recommended by EPRI (Exhibit NYS000167), at page vi, the Applicant has established an extensive inspection schedule, consistent with the Staff's position in AMP XI.M41 for buried piping without cathodic protection. Further, as recommended by NEI (Exhibits NYS000168, at page 6, and NYS000169 at page 5) – and as provided in GALL Report Revision 2, AMP XI.M41 (Exhibit NYS000147A-D) and the Staff's Final ISG (Exhibit NRC000162) – the Applicant has committed to use risk-ranking to select inspection locations, and its committed number of inspections exceeds those recommended in the NEI Report (NYS000169), at pages 10-16. NRC Staff Testimony (Exhibit NRCR00016), at 70-71.

It should be noted that both the NEI and EPRI documents recommend cathodic protection for situations where "the risk of failure is unacceptable" (NEI) or the "risk of failure is unacceptably high" (EPRI); neither organization recommended the use of cathodic protection for all "critical piping systems." As described in my testimony above, "failure" means a failure to maintain the pressure boundary integrity such that adequate flow and pressure cannot be delivered, not simply the occurrence of leakage from a piping system. Further, both NEI and EPRI recognize that the absence of cathodic protection may be addressed by other means, such as risk-ranking and the selection of locations to be inspected based on the consequences of failure. *See* NEI 09-14, Revision 1 (Exhibit NYS000168) at pages 6, 7, and 19. Similarly, EPRI-1016456 (Exhibit NYS000167) contains numerous statements which acknowledge that cathodic protection is not installed for all buried piping locations at all plants (e.g., pages v, 1-2, 2-9, 2-13, 3-2, A-2), and that the availability of cathodic protection should be considered during risk ranking and selection of inspection locations (page 2-4 and 2-19). Thus, at page 6-1, EPRI provides a similar set of recommendations as the NEI document, for locations where the risk of failure is "unacceptably high" (including coatings, cathodic protection, special fill, pipe replacement with a different material, and prompt leak detection). NRC Staff Testimony (Exhibit NRCR00016), at 71-72.

H. Summary

Based on the Staff's review of the Applicant's AMP for buried piping and tanks at Indian Point Units 2 and 3, and its assessment of Dr. Duquette's and New York's views concerning Contention NYS-5, the Staff concluded that the Applicant has demonstrated that the effects of aging on buried piping and tanks will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 C.F.R. § 54.21(a)(3). Further, based on its review of the Applicant's proposed UFSAR Supplement for this AMP, the Staff concluded that the proposed UFSAR Supplement provides an adequate summary description of the program, as required by 10 C.F.R. § 54.21(d). NRC Staff Testimony (Exhibit NRCR00016) at 72.

CONCLUSION

The Staff's conclusions regarding the adequacy of the Applicant's AMP for buried pipes and tanks reflect careful evaluation of the Applicant's LRA and related submittals, as presented in the SER and SER Supplement 1. Further, the Staff's testimony reflects careful consideration of the challenges presented by New York and Dr. Duquette. The Staff's evaluation and conclusions warrant that Contention NYS-5 be resolved in favor of the Applicant.

Respectfully submitted,

/Signed (electronically) by/

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