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Submitted: December 16, 2011

UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

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In re:	Docket Nos. 50-247-LR; 50-286-LR
License Renewal Application Submitted by	ASLBP No. 07-858-03-LR-BD01
Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.	DPR-26, DPR-64
	December 16, 2011

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REPORT OF
DR. DAVID J. DUQUETTE, Ph.D
IN SUPPORT OF
CONTENTION NYS-5

Prepared for the State of New York

Office of the Attorney General

PROFESSIONAL QUALIFICATIONS

Professional Qualifications

David J. Duquette, Ph.D.

Dr. David J. Duquette is the John Tod Horton Professor of Engineering at Rensselaer Polytechnic Institute and a member of the Department of Materials Science and Engineering. He is a graduate of the United States Coast Guard Academy and the Massachusetts Institute of Technology. He performed his graduate work at the Corrosion Laboratory at the Massachusetts Institute of Technology (MIT), spent two years as a Research Associate at the Advanced Materials Research and Development Laboratory at Pratt and Whitney Aircraft prior to joining the faculty at Rensselaer. Dr. Duquette's research is primarily in the area of corrosion science and engineering. He has supervised more than 50 graduate research dissertations in corrosion and related sciences. He is the author or co-author of more than 230 publications and 20 book chapters. He presents invited lectures internationally 20 to 25 times per year. Among his awards, he has been elected a Fellow of three learned societies, ASMI (formerly the American Society of Metals), NACE (formerly known as the National Association of Corrosion Engineers) and ECS (the Electrochemical Society). He has received the Whitney Award of NACE for outstanding corrosion research, an A. v. Humboldt Senior Scientist Award from the German government, and a number of other awards from the scientific community. Dr. Duquette has just completed nine years of service on the United States Nuclear Waste Technical Review Board, having been appointed to the Board by President Bush in 2002. In addition to his academic duties, Dr. Duquette maintains an active consulting practice, primarily in the area of corrosion and mechanical failures.

A REVIEW OF
ENTERGY'S PROPOSED AGING MANAGEMENT PROGRAM (AMP) AT INDIAN POINT ENERGY CENTER (IPEC)

EXECUTIVE SUMMARY

Entergy has submitted a license renewal application (LRA) to the Nuclear Regulatory Commission (NRC) to continue to operate two of the nuclear power generation units (IP2 and IP3) at the Indian Point Energy Center (IPEC) for an additional period of 20 years. New York State (NYS) has expressed some concerns about safety of some of the IPEC infrastructures because of aging of those infrastructures. Accordingly NYS has filed contentions with the NRC regarding Entergy's Aging Management Plans (AMP) at IPEC. In particular there is some concern about external (soil) corrosion in buried piping systems, in particular those that carry radioactive materials or may affect the safe operation of the plant. I note that although Entergy and NRC Staff refer to "underground" piping systems which includes piping not in direct contact with soil, this report deals primarily with underground piping systems that are in direct contact with soil, which I refer to as "buried."

Entergy submitted an AMP that originally promised to perform only periodic or opportunistic inspections. However, independent from the AMP for buried piping submitted with the LRA, Entergy claims to be committed to NEI's "Industry Guidance for the Development of Inspection Plans for Buried Piping", which recommends that the specific inspections and examinations that are performed will be based on degradation observed or expected, the susceptibility of the pipe to leakage, the consequences of the leak, and the location of the pipe, rather than a simple scheduled periodic inspection program. Entergy has also endorsed Electric Power Research Institute (EPRI) recommendations that specify not only periodic and opportunistic inspections, but inspections based on local conditions of the piping. Both the NEI and EPRI documents recommend cathodic protection for critical piping systems.[1]

Entergy has also indicated in its AMP for buried piping at IPEC that they will perform inspections in accordance with NUREG-1801 Section XI.M34. However, there is a newer version of NUREG-1801 (Section XI.M41). The newer version of NUREG-1801 mirrors NUREG-1801 Section XI.34 in requiring periodic inspections, but also specifies that coatings and cathodic protection should be provided for buried carbon steel piping.

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[1] EPRI, Recommendations for an Effective Program to Control the Degradation of Buried Pipe (Dec. 2008); Guideline for the Management of Underground Piping and Tank Integrity", NEI 09-14 (Rev.1).

Based on the results of a review of documents provided by Entergy, New York State's contention that Entergy's LRA does not adequately provide adequate provision for corrosion inspection or monitoring is certainly valid. Furthermore Entergy has not supplied any information for corrosion mitigation of the buried piping at IPEC; that is, Entergy has identified an inspection schedule, but has not explained what it will do to address problems identified by the inspections. Specifically, Entergy does not commit to repairing its non-functioning cathodic protection systems despite committing to do so through industry initiatives, and despite its own consultant and its own manuals' recommendations to do so, and Entergy has not published acceptance criteria or any other means of assessing whether or not its AMP and affiliated documents are sufficient to manage aging at this rather old plant.

A REVIEW OF ENTERGY'S PROPOSED AGING MANAGEMENT PROGRAM (AMP) AT INDIAN POINT ENERGY CENTER (IPEC)

INTRODUCTION

Indian Point Energy Center (IPEC) has filed a license renewal application (LRA) for an additional 20 years of operation. As part of the LRA, IPEC has submitted an Aging Management Program (AMP). Section B.1.6 of the LRA refers to a program to inspect buried piping and tanks that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion. The AMP states that the inspection program will be consistent with program attributes described in NUREG-1801, Section XI.M34. The AMP was updated as a submission to the NRC on August 6, 2009 (NL-09-111) and again on July 14 , 2011 (NL-11-074). The AMP introduces the concept of inspection without specifying how the inspection program will be developed. There are, however, internal documents that appear to address implementation. These include CEP-UPT-0100 "Underground Piping and Tanks Inspection and Monitoring", issued 31 October 2011, EN-DC-343 (Rev. 4), "Underground Piping and Tanks Inspection and Monitoring Program", an inclusion in the IPEC Nuclear Management Manual, issued May 16, 2011, and SEP-UIP-IPEC, "Indian Point 2 & 3 Underground Components Inspection Plan" approved April 29, 2011. However, Entergy has not incorporated these internal documents into its commitments to the NRC, and it does not appear that Entergy believes the documents to be binding.

This report addresses the IPEC AMP and points to some perceived deficiencies in the AMP and its implementation documents. For the purposes of this report, underground pipes and piping systems are synonymous with buried pipes and piping systems, and will be limited to those pipes and piping systems in contact with soil.

TECHNICAL BACKGROUND ON CORROSION

Underground (Soil) Corrosion

In underground piping systems corrosion of metals and alloys occurs when water comes into contact with the metal. The following is a rather simplistic introduction to the corrosion of underground piping systems. Corrosion rates of metals can be very slow in pure deaerated water, but the presence of oxygen, which is admitted to the water from air in most engineering cases, greatly increases the corrosion rates. The corrosion reactions occur because the metal is oxidized by the oxygen, with the production of hydroxyl ions, because of the combination of water and oxygen. The metal is oxidized to a positive ion with the surrender of one or more electrons. The site on which this reaction occurs is called the anode. The electrons that are released from the anode participate in the reduction of dissolved oxygen, to produce hydroxide, on local sites called cathodes. In neutral solutions, $4<pH<10$, the positively charged metal ions combine with the hydroxide, which has a negative charge, to form a nearly insoluble compound. When the metal is iron, the metal hydroxide that is formed is generically called “rust”- $Fe(OH)_3$. In general, if rust is deposited on the surface of an iron based material, it will have a protective role, reducing the rate of oxygen arrival to the metal surface and accordingly reducing the general corrosion rate.

Factors that affect the corrosivity of water to iron based surfaces include the aforementioned levels of oxygen, the conductivity of the water, the specific ion concentration of the water, and the pH of the water. The conductivity of the water is important because the local anodic sites on a surface can only react with equivalent cathodic sites. If water has a low conductivity the distance between anodes and cathodes is limited. In high conductivity solutions anodes and cathodes can be widely spaced allowing more interaction between surface sites.

The vast majority of piping systems are constructed from either low carbon steel (sometimes called mild steel), or cast iron. Both of these materials are iron based.

In near neutral environments the specific structure of the steel or cast iron does not have a strong effect on the corrosion behavior. There are, of course many miles of pipe that are constructed of stainless steel, copper alloys or, in rare cases titanium alloys, as well as non-metallic materials such as HDPE or PVC. However, those materials will show appreciable corrosion only under rather severe conditions, and accordingly will not be addressed in this report. Additionally, I do not believe them to be present in high numbers, at Indian Point (Entergy's consultant PCA Engineers has stated that the majority of underground pipes at Indian Point are welded carbon steel). Steel and cast iron pipes can suffer from internal corrosion, but the thrust of this report will be a discussion of external corrosion of pipes, specifically those in contact with soils, the factors that affect external corrosion, and the steps that may be taken to mitigate external corrosion of buried pipe.

Factors Affecting External Corrosion of Pipes

Soils can be considered to be a kind of poultice, or sponge, when they are in contact with underground piping systems. Accordingly they will hold water against a pipe surface for extended periods of time even after the external environment has changed from wet to dry. Thus, rain at the surface of the ground will provide water to the soil, but the soil may stay saturated with water for long periods after precipitation ceases. Soils may also contain soluble species such as nitrates, sulfates, chlorides, organic compounds, etc. Each of these species, alone or in combination, can dramatically affect corrosion rates of buried metals. The effects may range from simply increasing the conductivity of the soil, or by reducing the effectiveness of otherwise protective corrosion products (for example, chlorides or the addition of weak acids that may deleteriously affect the protective properties of corrosion product films or may even make soluble corrosion products). The ability of a soil to retain water and the chemical make-up of the soil are paramount in affecting the corrosion behavior of buried metals such as the iron based alloys used for piping systems.

CORROSION PREVENTION

Prevention of Underground Corrosion of Buried Pipelines

Applied Coatings

Most steel and cast iron pipes that are intended for long service and are buried use some form of protection from corrosion by soils. Usually some level of protection is afforded by the application of surface coatings. These coatings range from simple painted surfaces, e.g. conventional or epoxy paints, to the use of sacrificial coatings such as galvanizing. In some cases enamels are used while in other cases bituminous coatings such as coal tar are utilized. Other types of coatings include tape wraps that may range from paper to polymer based tapes. In many cases, if wrapping is used, a second layer of coating may be applied over the wrapping. Even with coated pipes, however, there is always a concern about breaks in the coatings (holidays), either introduced during the coating process, installation of the pipes or damage induced after installation. When breaks in the coating occur the corrosion damage, in some cases, can be more severe than if the there is no coating at all. At breaks in the coating all of the corrosion damage may be concentrated in a single location so that a deep pit may perforate the pipe. Another possibility is that the interface between the coating and the pipe surface may introduce an effective crevice. Crevice corrosion can be especially damaging because the electrolyte chemistry in a crevice tends to be much more aggressive than the bulk electrolyte. In order to prevent localized corrosion at holidays in coatings, cathodic protection is often used.

Cathodic Protection

Iron based alloys including linepipe steels can be protected from corrosion by cathodic protection. Cathodic protection effectively lowers the electrochemical potential of steel to a potential that is below that required to oxidize the steel. Another way of expressing that is in the electrochemical couple between a sacrificial coating such as zinc and steel, the steel becomes the cathode while the zinc becomes the anode. The zinc then corrodes in a "sacrificial" manner to protect the steel. If the zinc coats the steel the steel is said to be "galvanized". In many cases the zinc anodes can also be placed in the same electrolyte as the steel (in the case of IPEC, in water saturated soil). As long as there is electrical contact between the zinc and the steel the zinc will preferentially corrode. There are distinct disadvantages to using zinc coatings or zinc anodes to protect steel from corrosion. In the first instance (coatings)the lifetime of zinc coatings is rather limited, and once the zinc coating has corroded away the underlying steel is subject to corrosion. In the second instance (replaceable anodes) the zinc anodes also have a limited lifetime and must be monitored, retrieved, and replaced on a regular basis. For many buried structures the maintenance period is on the order of a year. From an operating plant point of view the most efficient method for protecting buried structures from corrosion is an impressed current system. When metals corrode the metal becomes a positively charged ion with the release of one or more electrons. It is those electrons that are available to reduce some dissolved species in the environment. In near neutral environments such as water in most soils, dissolved oxygen in the aqueous environment is often the species reduced to produce hydroxide. The hydroxide is then available to combine with the positively charged ions produced by the corrosion reaction to produce a sparingly soluble metal hydroxide, or hydrated metal oxide; rust in the case of iron alloys. If electrons can be provided to the metal surface from an external source, the metal will not become oxidized (become positively charged), and corrosion will effectively be reduced or stifled altogether. The application of current in this manner is known as an impressed current system and requires a DC power supply to deliver electrons from an anode to the metal surface. The anodes in this case are usually conducting but inert materials. For example graphite is often used as an anode. From a thermodynamic point of view the application of current to the metal lowers the electrochemical potential of the metal to a level where corrosion cannot occur. The method for measuring the effectiveness of impressed cathodic protection systems, especially for buried steel structures, is to measure the potential of the steel vs. an electrode that has a standard potential. The most commonly used standard electrode is a copper/copper sulfate electrode that has a standard or reference potential of +0.314 volts. For most impressed current systems used to protect steel from corrosion, the measured potential that will provide complete protection is considered to be -0.85 volts vs. the standard copper-copper sulfate electrode.

A potential disadvantage of impressed current systems for buried structures is that the amount of current required to "polarize" the steel to the protection potential criterion is proportional to the surface area of the steel to be protected. For "bare" pipes this can require a significant amount of power. However, for pipes that are wrapped or coated, the cathodic protection system need only protect the "holidays" and the power requirements are greatly reduced. A further important consideration is that the conductivity of the soil becomes very important because of current-resistance losses in the soil. Thus spacing of the anodes becomes an important aspect of any impressed current cathodic protection system. Nevertheless, design criteria are readily available for installation of anodes if soil conductivities are known. The amount of current that is required to control corrosion of buried steel structures, especially pipelines, is generally controlled by applying coatings to the steel. Accordingly the current is only required to protect the areas exposed by the holidays in the coatings (see discussion of applied coatings above). The holidays may be incorporated into the coatings during application, or may be induced by damage or deterioration of the coatings after emplacement of the structures.

Corrosion Protection for Buried Piping Systems at Nuclear Power Generating Plants

In May 2007 EPRI conducted a Nuclear Power Plants Piping Integrity Workshop with a follow up in October 2007.[2] At those meetings the integrity of buried pipe was identified as one of the industry's top priorities. More than 40 industry representatives attended those workshops. (Note that four Entergy representatives are identified as contributors to the report).[3] At those workshops the problems of both internal and external corrosion were discussed, with the conclusion that identification of the degradation of buried pipes is challenging to assess since the pipes are difficult to reach for inspection.

Based on the results of those workshops EPRI issued a buried pipeline management document entitled "Recommendations for an Effective Program to Control the Degradation of Buried Pipe", dated December 2008.[4] The EPRI program contains six elements: (1) developing a corporate program including training, implementing procedures, documentation, and performance indicators; (2) prioritizing buried pipe systems and locations to be inspected based on risk of failure (including likelihood and consequence of failure); (3) performing direct inspections to quantify the degree of degradation and damage; (4) evaluating the fitness-for-service of degraded buried pipes; (5) selecting the appropriate repair technique where required, including both

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[2] EPRI, Recommendations for an Effective Program to Control the Degradation of Buried Pipe (Dec. 2008) at v.
[3] EPRI, Recommendations for an Effective Program to Control the Degradation of Buried Pipe (Dec. 2008).
[4] EPRI, Recommendations for an Effective Program to Control the Degradation of Buried Pipe (Dec. 2008).

non-welded and welded repairs; and (6) taking preventive actions to reduce the risk (likelihood and consequence) of future leaks or failures.[5]

In 2010 the Nuclear Energy Institute (NEI) also issued a report entitled "Guideline for the Management of Underground Piping and Tank Integrity", NEI 09-14 (Rev.1).[6] This guideline describes the policy and practices that the industry commits to follow in managing underground piping and tanks. The NEI document states that the specific inspections and examinations that are performed will be based on degradation observed or expected, the susceptibility of the pipe to leakage, the consequences of the leak, and the location of the pipe. The document further details the number of inspections that should be required, especially for those lines that carry Licensed Material.

In April of 2011, the Buried Pipe Integrity Task Force, which is affiliated with NEI, issued a document entitled "Industry Guidance for the Development of Inspection Plans for Buried Piping". This document cites criteria for inspection, including, depending on pipe length, two, or in some cases three "direct examinations of the highest susceptible locations, with acceptable results, may be sufficient to demonstrate reasonable assurance".[7] The phraseology "highest susceptible locations" is critical since susceptibility of buried pipes to corrosion is determined by the characteristics of the soil/water combination at <u>all</u> locations at a given site. Accordingly it is paramount that, as a minimum, soil conductivity, chemistry, drainage, and water retention are characterized to determine the best locations for direct measurements. However, even this protocol will not identify serendipitous locations that have been identified at plants around the country such as those cited in the NY State contention on buried pipes cited below.

CORROSION OF BURIED PIPING AT INDIAN POINT

Leaking Pipes at IPEC

Indian Point has not been immune from ground water contamination. Tritium was

[5] EPRI, Recommendations for an Effective Program to Control the Degradation of Buried Pipe (Dec. 2008).
[6] Guideline for the Management of Underground Piping and Tank Integrity", NEI 09-14 (Rev.1)
[7] Buried Pipe Integrity Task Force, "Industry Guidance for the Development of Inspection Plans for Buried Piping" (Apr. 2011).

detected in the ground water at IPEC. In 2005 tritium in the ground water was ascribed to a crack in one of the spent fuel pools. Again, in 2006, tritium, as well as strontium-90, nickel-63 and cesium were detected in a location close to the Hudson River, and under the site. In 2007 tritium was detected in steam venting from a buried pipe that runs between units 2 and 3.[8]

As recently as 2009 a leak was detected in a carbon steel underground recirculating line that resulted in a shutdown of the plant for seven days.[9] While no radioactive materials were nominally carried in the pipe that leaked, the function of the pipe is safety related and the pipes are now designated as high impact, medium corrosion risk, and high inspection priority. The root cause analysis of the leak indicated that there was damage to the bituminous coating due to backfill.[10] The line was not cathodically protected (see discussion on cathodic protection at IPEC). Interestingly, an earlier assessment of the line indicated that the soil conditions, at the time of installation, did not require active corrosion control.[11] While this particular line nominally does not carry radioactive materials, the failure of an inspection process and the assumption that the soil in contact with the pipe was non-corrosive, provides a cautionary tale about the condition of all of the buried piping at Indian Point. The root cause analysis cited here for the 2009 leak states:

> According to the Unit 2 and Unit 3 USFAR's, the basis for not providing cathodic protection systems for buried piping was an engineering study performed during original licensing of the plants. Determinations of the soil resistivities at locations away from the river were concluded to be sufficiently high to preclude the need for cathodic protection of buried piping. The study recommended the application of protective coating to prevent local corrosion attack. Based on recent resistivity testing, the original resistivity determinations remain consistent.[12]

Clearly the determinations of soil resistivity and the ensuing recommendation were not sufficient to prevent the leak in the condensate storage tank return line. Nor would IPEC's proposed inspection program have been sufficient to have identified

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8 IPEC report CR-IP2-2009-00666.
9 IPEC report CR-IP2-2009-00666.
10 IPEC report CR-IP2-2009-00666
11 IPEC report CR-IP2-2009-00666 at 7 of 39.
12 IPEC report CR-IP2-2009-00666 at 12 of 39.

the possibility of a leak in this buried pipe. (See discussion of cathodic protection and buried piping inspections below).

Entergy's LRA AMP for Buried Piping at IPEC

Among the important recommendations that both the EPRI report and the NEI report make is that a buried pipe integrity program plan, and implementing procedures, should be developed. Entergy has indicated in the LRA that such a plan is being developed but that development will not be completed until September 28, 2013 for IP2 and December 12, 2015 for IP3. Both dates are after the scheduled completion of these hearings. The following discussion summarizes Entergy's efforts to create a buried piping and tanks inspection and management program.

Section B.1.6 of Entergy's LRA refers to a program to inspect buried piping and tanks that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion. The AMP states that the inspection program will be consistent with program attributes described in NUREG-1801, Section XI.M34. Section B.1.6 said only the following:

> 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. The program applies to buried components in the following systems.
>
> - Safety injection
> - Service water
> - Fire protection
> - Fuel oil
> - Security generator
> - City water
> - Plant drains
> - Auxiliary feedwater

> Of these systems, only the safety injection system contains radioactive fluids during normal operations. The safety injection system buried components are stainless steel. Stainless steel is used in the safety injection system for its corrosion resistance.
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> Prior to entering the period of extended operation, plant operating experience will be reviewed to verify that an inspection occurred within the past ten years. If an inspection did not occur, a focused inspection will be performed prior to the period of extended operation. A focused inspection will be performed within the first ten years of the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. The program will be implemented prior to the period of extended operation.[13]

I believe that Entergy considered this minimal statement to be its AMP. Based on this language, it is impossible to ascertain what exactly Entergy would be doing to manage pipes, but it is clear that Entergy originally intended its AMP to include only opportunistic inspections. The AMP was updated as a submission to the NRC on August 6, 2009 (NL-09-111). The revised commitment reads:

> Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium, or low impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.[14]

In July of 2011, Entergy again amended its commitment to replace the last line with "Perform inspections using direct visual inspection."[15] Accompanying, but not incorporated into, the revised commitment Entergy also stated the following:

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[13] LRA, section B.1.6.
[14] NL-09-111, Attachment 2, p. 2 of 11.
[15] NL-11-074, Attachment 2, p. 1 of 17.

> Prior to entering the period of extended operation, plant operating experience will be reviewed and multiple inspections will be completed within the past ten years. Additional periodic inspections will be performed within the first ten years of the period of extended operation.
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> IP2 will perform 20 direct visual inspections of buried piping during the 10 year period prior [sic] 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.
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> IP3 will perform 14 direct visual inspections of buried piping during the 10 year period prior [sic] 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 20 during each 10-year period of the PEO. [16]

This language does not appear in the commitment itself, but only in Entergy's response to NRC's Request for Additional Information. Similar language had appeared a few months prior in another Response to Request for Information.[17] The AMP does introduce the concept of inspection but does not specify how the inspection program will be implemented. There are, however, internal documents that appear to address implementation. These include EN-DC-343 (Rev. 4), "Underground Piping and Tanks Inspection and Monitoring Program", an inclusion in the IPEC Nuclear Management Manual, issued May 16, 2011; CEP-UPT-0100

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[16] NL-11-074, Attachment 2, p. 3-4 of 17. I note that previous versions of this document referred to the Program as the "Buried" Piping and Tanks Inspection and Monitoring Program.

[17] NL-11-032, Attachment 1 (Mar. 28, 2011)

"Underground Piping and Tanks Inspection and Monitoring", issued 31 October 2011, and SEP-UIP-IPEC, "Indian Point 2 & 3 Underground Components Inspection Plan" approved April 29, 2011. I summarize them below. However, these internal documents are also not included in the commitment from Entergy or made a part of the LRA. They are presumably subject to modification by Entergy without NRC approval and would not be obligations imposed on Entergy by a renewed license.

EN-DC-343, Revision 4: Underground Piping and Tanks Inspection and Monitoring Program

This fleetwide Nuclear Management Manual "provides the requirements for each site to develop its own site specific Underground Piping and Tanks (UPT) Inspection and Monitoring Program [and] provides a set of recommendations for Entergy nuclear power plants to use in implementing an effective program to detect and mitigate life-limiting degradation that may occur in underground piping systems and tanks."[18] It acknowledges that "The risk of a failure caused by corrosion, directly or indirectly represents the most common hazard associated with underground piping and tanks."[19] It "consists of inspection and monitoring of selected operational underground piping and tanks for <u>external</u> corrosion" and indicates that the details of the risk ranking criteria, reasonable assurance guidance, recommendations for inspection, monitoring, and mitigation portion of this Program are contained in CEP-UPT-0100. It states "This procedure and CEP-UPT-0100 contain the required elements to help Program Owners prioritize inspections of underground segments, evaluate the inspection results, make fitness for service decisions, select a repair technique where required, and take preventive measures to reduce the likelihood and consequence of failure."[20]

The procedures and oversight section of EN-DC-343 refers to Entergy's document CEP-UPT-0100 as the requirement associated with the scope, risk ranking and examination techniques to be followed. In the risk ranking section, an assemblage of a set 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. The remainder of the document details the inspection and monitoring program into Risk Ranking, Inspections, Fitness for Service, Repairs, and Prevention, Mitigation and Long term Strategies.

EN-DC-343 calls for each plant to develop its own site-specific Underground Piping and Tanks Inspection and Monitoring Program. However, I have not been provided

[18] EN-DC-343, Rev. 4.
[19] EN-DC-343, Rev. 4.
[20] EN-DC-343, Rev. 4 at 4.

with an Indian Point-specific Program, and have reviewed only Entergy's fleetwide program. Nor am I aware that one exists. Thus, I cannot assess what Indian Point's specific program will entail.

With regard to repairs, EN-DC-343 says only that "Contingency planning should be in place for prompt implementation in case an underground segment fails to meet acceptance criteria."[21] But Entergy has not provided its acceptance criteria, making it impossible to assess its aging management program's effectiveness.

In terms of prevention of leaks, Entergy offers only that "Where the risk of failure is unacceptable, [unspecified] preventive measures and options to mitigate the possible leakage should be implemented."[22] EN-DC-343 calls for newly installed piping to be coated, that proper use of fill should be used when excavating and re-burying components, and that baseline inspections should be performed prior to piping installation. However, this is not an aging management program. These are simply best practices for any underground pipes, and do not indicate any efforts that will be taken to manage already-aging pipes such as those present at Indian Point. EN-DC-343 goes on to say that for plants with installed cathodic protection systems for underground piping and tanks, Entergy should ensure that the proper operation of the systems is verified semi-annually. EN-DC-343 calls for cathodic protection degradation affecting safety-related structures, systems, and components (SSCs) to be repaired with "the Work Week T-process", which I presume to be an expeditious schedule (as compared with the non-safety-related SSCs, which are to be repaired within only six months of detection of a problem). Entergy has widespread cathodic protection system degradation of both safety and non-safety-related SSCs at Indian Point, and has not committed to repairing those systems. It does not appear that Entergy is proposing to implement EN-DC-343 at Indian Point, and Entergy does not commit to following all the recommendations in EN-DC-343.

EN-DC-343 further states that the program will be consistent with NUREG-1801, Revision One, Section XI.M34 (Buried Piping and Tanks Inspection). However, a new NUREG-1801 XI.M41 was issued in December 2010. In NUREG-1801 XI.M41, preventive actions for corrosion prevention include coatings, and/or wrappings and cathodic protection of buried pipes, while NUREG-1801 XI.M34 only addresses coatings and wrapping. NUREG-1801 XI.M34 explicitly does not require cathodic protection. As a minimum, IPEC should amend its commitments to comply with the recommendations of the EPRI report and the NEI report with respect to

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[21] EN-DC-343, Rev. 4 at 16.
[22] EN-DC-343, Rev. 4 at 16.

cathodic protection systems, and should be consistent with the December 2010 GALL Report. Entergy is not even in compliance with industry initiatives which it assisted in creating, nor is there any indication that it will comply in the future.

CEP-UPT-0100, Rev. 0: Underground Piping and Tanks Inspection and Monitoring

CEP-UPT-0100 is a fleetwide Entergy Nuclear Engineering Program which cites the GALL Report as its regulatory basis, but notes that the revision of GALL that applies depends on when a plant was relicensed and what commitments were made.[23] It also references NEI-09-14, an industry guidance document, as well as NEI-95-10 as relevant industry guidance and commitments.

CEP-UPT-0100 contains the specifics of how to classify a plant's pipes. As noted above, for these purposes, it is relevant to know only that Entergy "consider[s] any piping/tanks containing radioactive material high risk and automatically ranked as a "High Inspection Priority."[24] Entergy also requires the plant owner to conduct further risk ranking of piping and tanks containing radioactive material using the methodology developed in Engineering Report ECH-EP-10-00001, "Radiological SSC Groundwater Initiative Risk Evaluation Criteria" to prioritize radioactive or contaminated piping and tanks in relation to each other.[25] Entergy is then to group pipes together depending on the specific features of the components for inspection. Since Entergy has not provided a risk ranking for either individual or groups of pipes at Indian Point, I cannot assess how accurately it has ranked or grouped its pipes and tanks pursuant to these requirements. Furthermore, because of the lack of details and acceptance criteria, it is not possible to assess the adequacy of this program.. CEP-UPT-0100 also explains how examinations should take place of the grouped lines or segments of lines, and includes inspection methodologies for underground pipes and tanks, specifically including direct examination options (internal pigs and local pipe NDE) and indirect examination options including guided wave.[26] Entergy has not committed to comply with the recommendations of CEP-UPT-0100, its own internal guidance document.

Perhaps the most critical section of CEP-UPT-0100 is section 5.5, however, entitled "Evaluation of Inspection Data." This section states that "Acceptance criteria for any degradation of external coating, wrapping, and pipe wall or tank plate thickness shall be developed **prior** to performing opportunistic and scheduled inspections." (emphasis in original). It states that "Acceptance criteria are published in approved engineering documents" and that "Piping with measured wall thickness

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[23] CEP-UPT-0100, Rev. 0, at 9.
[24] CEP-UPT-0100, Rev. 0, at Table 9-1.
[25] CEP-UPT-0100, Rev. 0, at 10.
[26] CEP-UPT-0100, Rev. 0, at 14-15.

less than 1/16" will be repaired/replaced." It states also that "A condition report shall be initiated when measured wall thickness is found to be less than 87.5% of nominal thickness."[27]

In terms of preventive actions, it states that "existing [cathodic protection] systems may be upgraded or a new [cathodic protection] system installed" and requires that plants with installed cathodic protection systems verify proper operation of these systems, periodically test them, ensure the system is evaluated in accordance with EN-DC-343, put an individual in charge of the cathodic protection system, and verify that cathodic protection systems are corrected on a schedule commensurate with the safety significance of the system or component being protected.[28] Entergy has not committed to taking any of these actions at Indian Point despite knowing for years that its cathodic protection systems had fallen into disrepair, and has not committed to repairing them now.

SEP-UIP-IPEC, Rev. 0: Indian Point 2 & 3 Underground Components Inspection Plan

Program Section No. SEP-UIP-IPEC, the Underground Components Inspection Plan, appears to be the only Indian Point-specific document Entergy produced in this line of buried piping management manuals and programs. It "represents a specific commitment milestone in the NEI Industry Initiative", according to the document itself. SEP-UIP-IPEC acknowledges that although many buried or underground lines were once cathodically protected, such cathodic protection systems have lapsed, accelerating external corrosion where the coating has failed.[29]

SEP-UIP-IPEC notes that there are currently no industry guidelines for determining and achieving "Reasonable Assurance (RA) of Integrity" for inspected SSCs but that Entergy aims to achieve RA with a combination of a Fitness-for-Service engineering evaluation, indirect inspections, direct examinations, and remediation if necessary. Through this combination, Entergy believes a "high level of confidence that the structural and/or leakage integrity of the underground SSCs will be maintained."[30]

SEP-UIP-IPEC reiterates the risk ranking scheme laid out in EN-DC-343 and CEP-UPT-0100 and states that "An effective cathodic protection system is essential to minimize underground piping corrosion." However, it observes that Indian Point's cathodic protection systems were "rarely maintained" and were in some cases

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[27] CEP-UPT-0100, Rev. 0, at 16.
[28] CEP-UPT-0100, Rev. 0, at 16.
[29] SEP-UIP-IPEC, Rev. 0, at 5.
[30] SEP-UIP-IPEC, Rev. 0, at 9.

abandoned, rendering the systems incapable of providing the needed corrosion protection. SEP-UIP-IPEC recommends that Entergy conduct an Area Potential and Earth Current (APEC) Study to analyze and implement improvements to coatings and cathodic protection effectiveness.

SEP-UIP-IPEC makes no mention of the PCA report which had found that cathodic protection was necessary but lacking at Indian Point. SEP-UIP-IPEC only establishes a goal of determining if available cathodic protection has been operated properly prior to performing inspections.[31] SEP-UIP-IPEC does not require the implementation of cathodic protection at all, and certainly not as a prerequisite for license renewal.

In its revised Supplemental Safety Evaluation Report issued in August of this year, the NRC staff found that "although the service water, containment isolation support, auxiliary feedwater, plant drains, fuel oil, security diesel propane, and fire protection systems are not cathodically protected, the applicant's response is acceptable in that:

> • The applicant is risk informing its piping inspection locations to select those with the greatest potential for leakage.
>
> • The applicant is sampling the soil for corrosivity prior to and during the period of extended operation, using standard industry methodologies to determine soil corrosivity, and will be increasing the number of inspections if the soil is corrosive.
>
> • Steel piping is coated.
>
> • 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."[32]

I have reviewed the history of this site, with special attention to the fact that there

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[31] SEP-UIP-IPEC, Rev. 0, at 15.
[32] Supplemental Safety Evaluation Report (Aug. 2011) at section 3.0.3.1.2.

has already been at least one leak at this plant due to corrosion, and that in at least one location, piping degradation has reduced pipe wall thickness by 85% (that is, to only 15%).[33] At best, an aggressive inspection program can only identify the problem, and does not provide a solution to the problem. A properly applied cathodic protection program would prevent further corrosion and would accordingly inhibit any further leaks.

IPEC's AMP is deficient in describing the inspection protocols and implies that buried pipes will only be inspected opportunistically when maintenance requires sections of piping to be excavated (presumably they will also be inspected when leaks occur). NUREG-1801 in both the M34 and M41 versions does call for inspection of buried piping systems but only every ten years beginning 10 years prior to entry into the period of extended operation. Entergy appears to have adopted this inspection schedule in CEP-UPT-0100 but has not committed to adopting that schedule. Such a long period between inspections is questionable, especially for the highest risk piping systems. Given that this is a new program, it would appear that Entergy is committing to performing these pre-period of extended operation inspections in the next two to four years, which appears to be an unreasonable schedule for this number of inspections. Corrosion generally takes place very slowly, but its effects are cumulative. Accordingly if, at any inspection, some degree of deterioration of either the pipe or its protective coating is observed, it is appropriate to decrease the interval between inspection periods in order to monitor the rate of damage accumulation. As written, either version of NUREG 1801 would allow an interval of ten years between inspections even if significant coating or metal damage is observed at inspection. As a minimum an Aging Management Program should define criteria for when heightened inspections should occur and when there should be repair or replacement of systems that do show damage. Inspection and identification in the absence of remediation hardly equal management. While Entergy has indicated to the NRC that it will perform at IP3 "14 visual inspections of buried piping during the 10 year period prior to the PEO" and "16 direct visual inspections during each 10-year period of the PEO",[34] these statements are not incorporated into Entergy's AMP or commitments and thus it is not clear whether these are commitments to which Entergy is in fact committed. It is also not clear how many inspections, if any, have already taken place that Entergy is counting against this requirement but that were not

[33] Structural Integrity Associates, Inc, Report No. 0900235.401.R0 (Mar. 19, 2009) at 6.
[34] NL-11-074 (July 14, 2011); Supplemental Safety Evaluation Report (Aug. 2011).

conducted to the standards to which Entergy's new program would dictate they should be conducted.

NEI's "Industry Guidance for the Development of Inspection Plans for Buried Piping", which NEI says it expects every utility, including Entergy, to implement "in accordance with the intent of the Initiative," recommends that the specific inspections and examinations that are performed will be based on degradation observed or expected, the susceptibility of the pipe to leakage, the consequences of the leak, and the location of the pipe.[35] This document provides a much better set of criteria for inspection sequences than either NUREG 1801XI.M34 or IPEC's Aging Management Program. This document details the number of inspections that should be required, especially for those lines that carry Licensed Material. As stated above, the criterion cited is that two, or in some cases three, "direct examinations of the highest susceptible locations, with acceptable results, may be sufficient to demonstrate reasonable assurance".[36] The phraseology "highest susceptible locations" is critical since susceptibility of buried pipes to corrosion is determined by the characteristics of the soil/water combination at all locations at a given site. Accordingly it is paramount that soil conductivity, chemistry, drainage, and water retention are characterized to determine the best locations for direct measurements. The NEI document is also in accordance with NUREG 1801 XI.M41 in that it suggests an asset management plan that includes the results of cathodic protection testing as well as the addition or enhancement of cathodic protection to manage buried piping.

Cathodic Protection at Indian Point

In 2005 Entergy's System Engineering Department issued a condition report, IP2-2005-03902, which indicated that INPO had completed an investigation of the cathodic protection systems at IPEC, and had concluded that "The lack of a functioning cathodic protection system in severe environmental conditions leaves piping and structures susceptible to corrosion-induced failures."[37]

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[35] Letter, Alexander Marion (NEI) to Eric J. Leeds (NRC Office of Nuclear Reactor Regulation) dated November 3, 2010; Guideline for the Management of Underground Piping and Tank Integrity", NEI 09-14 (Rev.1).
[36] Buried Pipe Integrity Task Force, "Industry Guidance for the Development of Inspection Plans for Buried Piping" (Apr. 2011).
[37] IP2-2005-03902.

At Unit 1, which is no longer operating but shares some buried pipes with Units 2 and 3, a 1989 survey indicated that the cathodic protection system had deteriorated and was no longer functional.[38] The system was upgraded in 1993/1994 and was found to be functional in 1994 but was no longer functional in 2002.[39] Note that the cathodic protection system at Unit 1 seems to have been designed to provide cathodic protection to a dock, not a buried piping system.[40]

At Unit 2 the 1989 survey indicated that the cathodic protection system designed to protect circulation water lines, service water lines, bearing piles and metallic structures inside the intake structure, was no longer operational. A modification was performed in 2001 to bring the system back into operation but failed shortly after start-up. It was concluded that the cathodic protection system has not been providing adequate protection since 1989.[41]

At Unit 3 the entire cathodic protection system was "temporarily" removed in the mid 1980s and has not been re-installed.[42]

Recent Corrosion/Cathodic Protection Underground Field Survey

In 2008 Entergy commissioned PCA Engineering to perform a corrosion/cathodic protection field survey and assessment of underground structures associated with units 2 and 3 at IPEC.[43] The PCA review included the circulating water piping, the service water piping, the condensate piping and the city water piping systems. The PCA review of construction documents indicated that the majority of the piping systems are carbon steel with either a coal tar coating or tape wrapping. PCA also reported that a cathodic protection system had been installed for the intake structures and the service and circulating water piping. The 2008 report stated that the majority of these systems have been removed or are out of service. The PCA results indicated that virtually all of the structure to soil/water potential

[38] IP2-2005-03902.
[39] IP2-2005-03902.
[40] IP2-2005-03902.
[41] IP2-2005-03902.
[42] IP2-2005-03902.
[43] PCA Engineering, Inc.,"Corrosion/Cathodic Protection Field Survey and Assessment of Underground Structures at Indian Point Energy Center Unit Nos. 2 and 3 during October 2008" Nov. 10, 2008 (Revised Dec. 2, 2008)(Engineering Report No. IP-RPT-09-00011, Rev. 0).

measurements performed on the piping were well below the recommended potential of -850 mv. vs. the copper/copper sulfate electrode. Further, the circulating water piping was found to be electrically continuous to the plant copper grounding system. This results in a galvanic couple between the copper and the steel piping where the steel piping is anodic to the copper. A stray current problem between the cathodically protected Algonquin pipeline and the unprotected city water piping system that services the plant was also identified. Soil resistivity measurements conducted by PCA at 12 locations indicated that the resistivity ranged from approximately 8000 ohms/cm to approximately 63,000 ohm/cm. Eight of the locations indicated resistivities in the 10,000 ohm/cm to 30,000 ohm/cm range. Soils with resistivities in that range are considered to be mildly corrosive. The one location that measured a resistivity of approximately 8,000 ohm/cm is considered to be moderately corrosive.

Based on its survey, PCA recommended the installation of a mitigation bond, or sacrificial anodes, to protect the city water system from the stray current generated by the Algonquin pipeline. They also recommended the installation of a deepwell anode system for high priority piping services. Finally, they recommended establishing an inspection program based on API 570 (American Petroleum Institute Standard 570 – Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems). Entergy has indicated that it has cathodically protected its city water line, but it does not appear to have adopted any other of PCA's recommendations.[44] In Entergy's recent letter to the NRC, Entergy indicates that it will undertake soil testing and if the test results indicate the soil is corrosive, will increase the number of piping inspections to 20 during each 10-year period of the period of extended operation.[45] As stated above, Entergy's consultant's 2008 report already indicated the presence of corrosive soils at Indian Point. Entergy recognizes that a more frequent inspection program is appropriate given Indian Point's soil conditions but has not committed to implementing it.

Implementing the recommendations of the PCA report would have brought IPEC into reasonable agreement with NUREG-1801 Section XI.M41 for buried and underground pipes. However, as has been noted, Entergy has submitted its Aging Management Program for its LRA with the out-of-date NUREG-1801 Section XI.34. It is especially important to implement NUREG-1801 Section XI.M41 because Entergy has experienced both leaks and indications of coating damage at IPEC.

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[44] Supplemental Safety Evaluation Report at 3-3.
[45] NL-11-074 (July 14, 2011).

Condensate Storage Tank (CST) Underground Recirculating Line Leak at IPEC

As recently as February 2009, IPEC experienced a leak in an 8" CST return line carrying condensate.[46]. The leak resulted in a 7 day shut down of IP2. Entergy estimated the return line loss at 17 gpm or approximately 20,000 gallons per day. The root cause analysis attributed the leak to external corrosion of the pipe.

> "Patterns of corrosion on the piping and observations of the backfill indicate that corrosion of the pipe likely occurred at localized coating damage that occurred during installation of the pipe."[47]

A failure analysis and a subsequent inspection of the piping were conducted by Structural Integrity Associates (SI in Structural Integrity Associates reports and SIA in Entergy's reports) and reported in SI reports dated March 19, 2009, and May 15, 2009.[48] Inspection of the pipe after excavation revealed that there were a number of deep isolated pits. More generalized corrosion was also observed on an elbow removed from the CST return line. In their report SI also noted that the piping was not cathodically protected.[49]

SI also performed a long range guided wave (G-Scan) inspection of the CST return line two days after the leak was detected. Their results indicated that the external corrosion of the line has resulted in a 20% to 85% wall loss.[50]

In the March 19, 2009 report, SI opined that: "It is likely that similar corrosion exists on adjacent piping if exposed to comparable soil conditions". Entergy has not indicated that it has investigated the problem for adjacent piping or made repairs to adjacent piping based on such investigation

Although Entergy has concluded that there were no direct safety or radiological

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[46] Entergy Operations, IPEC, Root Cause Analysis, CR-IP2-2009-00666, 5/14/2009
[47] CR-IP2-2009-00666
[48] Structural Integrity Associates, Inc, Report No. 0900235.401.R0 (Mar. 19, 2009) and Report No. 0900235.402.R0 (May 15, 2009).
[49] Structural Integrity Associates, Inc, Report No. 0900235.401.R0 (Mar. 19, 2009)
[50] Structural Integrity Associates, Inc, Report No. 0900235.401.R0 (Mar. 19, 2009)

hazards associated with the leak in the CST return piping, the incident provides a cautionary note for all buried piping at IPEC. It is not clear whether any adjacent pipes are safety related or have the potential to carry radioactive fluids.

SUMMARY

New York State Contention vs. Entergy's AMP for Buried and Underground Piping IPEC

New York State has contended that the AMP contained in Entergy's LRA violates 10 C.F.R. sections 54.21 and 54.29(a) because it does not provide adequate inspection and monitoring for corrosion or leaks in all buried, systems or structures, and components that may convey or contain radioactively-contaminated water or other fluids and/or may be important for plant safety.

Entergy's LRA, section B.1.6 indicated that the Buried Piping and Tanks Inspection Program will be consistent with program attributes described in NUREG-1801, Section XI.M34. Clarifications of Entergy's AMP for buried piping were issued in NL-09-11 and NL-11-090. In those documents Entergy stated it will employ inspection methods recommended by EPRI. The EPRI report was issued in 2008 and a companion report was issued by NEI in 2010. Entergy has committed to implementing an inspection program for IP2 in September, 2013 and at IP3 in December, 2015, and indicates that this is a "new" program. Both of these dates are well within the extended operating period and beyond the scope of this hearing. It is not clear why it would take as long as 5 to 7 years after the publication of the EPRI guidelines to complete development of an adequate inspection program. Without seeing the actual program, including acceptance criteria and commitments to undertake repairs that Entergy intends to adopt, it is not possible to determine at this time whether the inspection program will meet the requirements for an adequate AMP. With reference to the inspection program being a "new" program, Entergy published an inspection schedule of buried pipes in 2008 (LO-IP3LO-2008-00151). That document stated that CST Inlet – 8" Line 1509 was inspected between 10-01-08 and 12-31-08. However it is exactly in that line that a leak occurred in 2009. It is not clear if all of the other inspections scheduled in LO-IP#LO-2008-00151 have been accomplished using a similar, and clearly inadequate, technique or what the results of those inspections were.

Entergy's LRA is lacking in detail as far as the specifics of their buried piping inspection program are concerned. Lacking the details of an inspection program, there is no possibility of assessing the adequacy of the inspection program. Further, an inspection program, *per se,* is not adequate to ensure the safe operation of engineering systems. The acceptability of the results of the inspection program, including the criteria to be applied to continued operation, remediation, or replacement, should be specified.

Entergy has stated that it will perform an inspection program at IPEC that is consistent with the outdated NUREG-1801 Section XI.M34, rather than the more comprehensive and more recent NUREG-1801 Section XI.M41. The newer NUREG-1801 specifies not only an inspection program but also specifies preventive actions for buried pipes and tanks. For carbon steel components NUREG-1801 Section XI.M41 specifies that buried piping should be coated and cathodically protected. There are no cathodic protection systems currently in operation at IPEC for the protection of safety related buried piping, and there are apparently no plans to either re-commission the existing inoperative systems or to install new systems.

Based on the results of this review of documents provided by Entergy, New York State's contention that Entergy's LRA does not adequately provide adequate provision for corrosion inspection or monitoring is certainly valid. Furthermore Entergy has not supplied any information for corrosion mitigation of the buried piping at IPEC.

As a minimum I recommend that Entergy take the following steps to create an aging management program that will adequately manage aging of buried pipes at Indian Point:

1. Adopt the recommendations of the NEI and EPRI reports, including cathodic protection of buried pipes.

2. Follow the dictates of NUREG-1801 Section XI.M41.

3. Clearly identify acceptance criteria for corrosion damage to buried pipes.

4. Clearly state the repair and remediation procedures to be followed if the corrosion damage lies outside of the acceptance criteria.

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