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Guidelines for Tank Inspections

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Guidelines for Tank Inspections

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PRODUCT DESCRIPTION

This report provides guidelines that nuclear power plant representatives who are responsible for tanks may use to develop a tank inspection plan. The report provides the following:

- An overview of typical tank terminology and structural characteristics along with an analysis of survey and tank inspection data from tank owners.
- A summary of existing tank inspection codes from institutions outside the nuclear industry and references to example checklists for aboveground and underground storage tanks.
- A description of relevant nondestructive evaluation (NDE) methods that are suitable for aboveground and underground storage tank inspections and a matrix that summarizes capabilities and limitations of existing NDE techniques.
- An investigation of the potential use of viable statistical analysis, techniques, and processes for extrapolating sample inspection results from a portion of a tank.

Background

In 2010, the Nuclear Energy Institute's "Guideline for the Management of Underground Piping and Tank Integrity" (NEI 09-14) was updated to include leak tightness expectations for buried and underground tanks. The Electric Power Research Institute (EPRI) has observed that there is a need within the nuclear power industry to perform inspections to verify leak tightness of underground and buried assets. Therefore, EPRI has published several reports that address prevention and mitigation of degradation and leaks of buried pipes, including the EPRI reports *Balance of Plant Corrosion—The Underground Piping and Tank Reference Guide: Revision 1* (1021470); *Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks* (1021175); and *Nondestructive Evaluation: Buried Pipe NDE Reference Guide—Revision 2, Addendum 1* (3002000447). The report herein focuses on tank inspections for the purpose of improving management of physical assets and increasing efficiency in performing tank inspections.

Objectives

The objective of this report is to provide guidelines and information that can be used to develop a tank inspection plan.

Approach

A literature review of existing codes, standards, and NDE techniques was used to gather data on relevant processes for inspecting tanks. In addition, a survey was distributed to utility member representatives who have responsibility over tanks at nuclear power plant sites. This information was cogently compiled into a single document to present input on tank design, tank materials, and inspection processes and techniques for nuclear power plant tanks.

Results

This report provides a summary of best practices that nuclear power plant tank owners can use to develop tank inspection plans. Future research needs are identified and include further investigation of the use of statistical analysis procedures to determine tank inspection areas. In addition, the investigation for this report resulted in information about potential NDE techniques that can be used for tank inspections.

Applications, Value, and Use

Tank owners at nuclear power plants can use this report to develop site-specific inspection plans for aboveground and underground storage tanks. Specifically, the report provides guidance on inspection locations and areas, inspection frequency, and relevant NDE techniques.

Keywords

Aboveground storage tank (AST)
Cathodic protection
Inspection intervals
Statistical analysis
Tank inspection
Underground storage tank (UST)

EXECUTIVE SUMMARY

Nuclear power plant personnel who are responsible for tanks have varying considerations to make when performing tank inspections and when developing tank inspection plans. For instance, an array of different types of tanks are found in the field, consisting of different materials and designs, such as post-tensioned concrete or welded steel. In addition, varying codes and standards that exist outside the nuclear industry provide differing expectations regarding tank inspection processes and frequency. For the nuclear industry, there is a lack of direction on tank inspection locations, frequency, and techniques such as nondestructive evaluation (NDE).

Through previous research on the integrity of buried pipe at nuclear power plants, the Electric Power Research Institute (EPRI) has recognized a growing need for plants to engage in tank-related inspections. As a result of EPRI's earlier work and the need for plants to maintain leak tightness of buried assets, the Nuclear Strategic Issues Advisory Committee (NSIAC) and the United States Nuclear Regulatory Commission (NRC) have issued guidance, including the NRC's "Generic Aging Lessons Learned (GALL) Report" (NUREG-1801), Section XI.M41, and the Nuclear Energy Institute's "Guideline for the Management of Underground Piping and Tank Integrity" (NEI 09-14, Rev. 3). Best practice for the comprehensive management of the integrity of piping and tanks at nuclear power plants includes inspecting those components and systems and documenting those inspections. The primary goal of this report is to provide guidelines from which plant personnel can develop site-specific tank inspection plans.

The project began with a member survey and review of several plant Underground Pipe and Tanks Integrity Initiative (UPTII) databases for existing information on installed tanks by system type, material, inspection locations and methods, flaws discovered, and so on. The data reviewed also provided details on the types of tank designs, the significance of tank contents, and the ages of tanks found at nuclear power plants. The results are presented as follows:

- Sections 1 and 2 and Appendix A provide the survey results and engineering analysis of general characteristics of installed tanks and correlate various tank characteristics with known tank failure mechanisms and inspection results.
- Section 3 describes the inspection recommendations found in two commonly referenced industry standards for aboveground storage tank inspections and disposition—American Petroleum Institute (API) standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," and Steel Tank Institute (STI) standard SP001, "Standard for Inspection of Aboveground Storage Tanks." Topics addressed include establishing inspection intervals, inspection modes and methods, recommended practices for recordkeeping, and dispositioning of inspection findings.

- Section 4 provides a similar description of the inspection of underground storage tanks based on a review of a relevant document provided by the United States Environmental Protection Agency. In concert with Section 4, Appendix B provides example daily, monthly, and annual inspection checklists for the inspection of underground storage tanks, and Appendix C provides similar inspection checklists for aboveground storage tanks.
- Section 5 provides a review of state-of-the-art tank inspection technologies. Both manual and robotic/autonomous techniques are described, as well as the application of monitoring technologies. Appendix D presents a matrix of NDE technologies suitable for tank inspections, including descriptions of the technologies and their capabilities and limitations.
- Section 6 reviews potential statistical methods that tank owners may use as part of their tank inspection plans. It also presents an idea for future research to determine the viability of using these statistical techniques to change the amount of tank area that is being inspected.

This report does not prescribe what a nuclear power plant's tank inspection program must or should contain. It offers a review and summary of several existing guidelines that are currently in use in other industries for nuclear power plant representatives to consider when developing their own tank inspection programs.

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1
INTRODUCTION

1.1 Background

In 2007, EPRI conducted two workshops that identified integrity of buried pipes as a significant issue for nuclear power plants. During the same period of time, NRC staff were asked to review regulation and develop a plan for buried piping and update requirements for license renewal which can be found in the latest Generic Aging Lessons Learned (GALL) report and industry initiatives related to leak tightness of piping were in early stages of development [1-3]. One result of the workshops was the EPRI-sponsored development of a recommendations document (EPRI report 1016456) to help plant engineers prevent and mitigate degradation and leaks in buried pipes [1]. In 2009, the Nuclear Strategic Issues Advisory Committee (NSIAC) pursued execution of the Buried Piping Integrity Initiative, which eventually led to NEI-09-14, Revision 3 titled, Guideline for the Management of Buried Piping Integrity. The document encourages the use of an inspection plan for assessment of "structural and leakage integrity and provide reasonable assurance" that structures and components will "maintain this integrity between successive inspections [2]." This initiative was an expansion of its original scope to include both buried and underground piping and tanks [3]. To date, emphasis has been on piping, and there are no detailed guidelines for tanks providing direction on where to inspect, how often to inspect, and what types of nondestructive (NDE) techniques should be used. The primary goal of this report is to provide those guidelines, allowing the reader to begin development of a tank inspection plan specific to their needs. This report is not intended to provide or prescribe an inspection plan and should not be taken as more than a guide.

1.2 Overview of the Document

In Section 2 this report provides an examination of historical information on existing NPP tanks, using data from the EPRI survey of member plants, as well as information taken directly from several plants' tank databases. Tanks are described by system, material, content, etc. Inspection locations and methods and flaws discovered are also discussed. An attempt is made to summarize general characteristics across the population of installed tanks and correlate various tank characteristics with known tank failure mechanisms.

As the report title suggests, the primary focus of this report is on the development of guidelines for the inspection of tanks at NPPs. As there are no guidelines available within the nuclear industry, these guidelines will be based on existing codes and standards currently in use in other industries. As such these guidelines should be applicable for non-nuclear power plants and other related facilities. The bulk of the report is devoted to this effort, with summaries provided for the relevant existing codes/standards, and guidelines for the application of those codes/standards to NPP tanks. When appropriate, easy to follow flowcharts are provided to guide the end user in the development of a proper tank inspection plan.

The portions of the report dealing with standards which recommend inspection intervals and practices are divided according to two major themes: recommendations for Aboveground Storage Tank (AST) inspections (Section 3) and recommendations for Underground Storage Tank (UST) inspections (Section 4). Two relevant standards exist for AST inspection. These are *American Petroleum Institute Standard 653: Tank Inspection, Repair, Alteration, and Reconstruction* [4], which is discussed in Section 3.1, and *Steel Tank Institute Standard SP001: Standard for the Inspection of Aboveground Storage Tanks* [5], which is discussed in Section 3.2.

The monitoring of the structural health of USTs is significantly different than what is typically practiced for ASTs. USTs are heavily regulated on both the federal and often the state levels, and newly constructed USTs must be built with several levels of secondary safeguards and corrosion protection systems. When considering what practice to implement for health monitoring of USTs, plant operators should consult what the federal government and their particular state mandates. To achieve consistency among plants in a fleet operating in multiple states, an analysis of the mandates of each state and development of a single set of practices that meet the minimum requirements of all states of operation may be beneficial. A list of contacts for each state can be found at the website for the EPA[1] and a list of regulations for each state can be found at additional websites[2] designed to support compliance of regulation. A general outline of the federal regulations will be given in this document in Section 4.1, as well as a few additional practices recommended by the Petroleum Equipment Institute (PEI), in Appendix B, which are to be performed on a daily, monthly, and yearly basis (see PEI website[3]).

It is worth noting here that there is a prevailing theme between the state and federal regulations. With UST health monitoring, most regulations do not concern themselves with active preventative damage monitoring with technologies such as ultrasonic testing (UT), magnetic flux leakage (MFL), etc., as is more common with ASTs. Instead, since USTs are required to be constructed with at least one secondary containment system, monitoring of USTs is more focused on rapid leak detection followed by quick repair, replacement, or decommissioning of the UST.

This document assumes the reader is familiar with the requirements for UST construction which are given in Code of Federal Regulations, 40 CFR Part 280.

Section 5 provides a detailed review of current NDE technologies used for tank inspections.

Finally, in Section 6 a brief review is provided of possible statistical methods that may allow for inspecting only a portion of a tank and using those inspection results as a justifiable representation of the entire tank. Suggestions for future research along this line are included.

[1] http://www.epa.gov/oust/states/statcon1.htm

[2] http://www.tanknology.com/ust-state-regulations.html

[3] at http://www.pei.org/Default.aspx?TabId=107

1.3 Terminology

The categories of tanks dealt with in this report are defined as follows:

Aboveground Storage Tank (AST) – For the purposes of this report, an AST is any tank that does not meet the definition of a UST (see below). This includes tanks that are resting directly on the ground, with less than 10% of their volume below grade, or on concrete pads or rings, as well as those suspended above the ground by supporting structures.

Underground Storage Tank (UST) – The definition given by NEI 09-14 (Rev 3) is used for the purposes of this report. It reads, "All tanks that are outside of buildings and sufficiently below grade such that there is a reasonable possibility that leakage from inaccessible portions of the tank may not be detected."[1] This is consistent with the US Environmental Protection Agency's definition of a UST as "any one or a combination of tanks that have 10% or more of their volume below the surface of the ground in which they are installed." [6] Note that neither of these definitions differentiates between tanks that are in contact with the soil and tanks that are below grade but not in direct contact with the soil (in a vault, for example). Both types fall within the UST category.

Other relevant terms used in this report are defined below.

Buried Storage Tank – A subset of UST (defined above) in which the tank makes direct contact with the soil environment.

Coating/Lining – A barrier applied to the surface of a susceptible material to prevent degradation due to interaction with the environment. Whether the barrier is considered a coating or a lining depends on which surface it is applied. A coating is applied to the outer surface of the material, to protect against the external environment (typically soil and/or water). A lining is applied to the inner surface of the material, to protect against the internal environment (fluid content, e.g., water, fuel, oil, etc.).

Non-Destructive Examination (NDE) – an inspection technique used to evaluate the properties of a material, component, or system without causing damage to the item being inspected.

Cathodic Protection (CP) – a method of reducing or eliminating the corrosion of a metal surface by making it the cathode of an electrochemical cell.

The following is a list of acronyms used within this report, along with their interpretations.

ACFM – Alternating Field Current Measurement

ANI – American Nuclear Insurers

API – American Petroleum Institute

ASNT – American Society of Nondestructive Testing

AST – Aboveground Storage Tank

CFR – Code of Federal Regulation

CP – Cathodic Protection

CRDM – Continuous Release Detection Methods

CS – Carbon Steel

DOC – Date of Construction

DOT – Department of Transportation

ECT – Eddy Current Testing

EPA – Environmental Protection Agency

EPRI – Electric Power Research Institute

FEI – Formal External Inspection

FII – Formal Internal Inspection

FRP – Fiber-Reinforced Plastic

ID – Inner or Inside Diameter

MFL – Magnetic Flux Leakage

MT – Magnetic Testing

NDE – Nondestructive Evaluation/Examination

NEI – Nuclear Energy Institute

NPP – Nuclear Power Plant

NUREG – Nuclear Regulatory Guide

OD – Outer or Outside Diameter

OEM – Original Equipment Manufacturers

PAUT – Phased Array Ultrasonic Testing

PEI – Petroleum Equipment Institute

RBI – Risk Based Inspection

SHM – Structural Health Monitoring

SS – Stainless Steel

STI – Steel Tank Institute

SWRI – Southwest Research Institute

TOFD – Time of Flight Diffraction

UPTII – Underground Pipe and Tanks Integrity Initiative

UST – Underground Storage Tank

UT – Ultrasonic Testing

UTS – Ultrasonic Scans

VB – Vacuum Box

2
REVIEW OF INDUSTRY TANK DATA

In early 2014, an EPRI member survey was conducted to gain information on storage tanks at NPPs. The survey included questions related to tank geometry, inspection history and information, categorizing flaw characteristics, and identifying maintenance practice such as coatings and cathodic protection. The information collected during this survey was analyzed to identify trends for use in tank inspection guidelines.

In total 49 survey responses were submitted by EPRI members. From the unique surveys, 30% provided complete responses (all questions had an answer), 57% provided partial responses (a portion of the questions were answered), and the remaining completed the first section of the survey, which contained information identifying the plant and the respondent. Consequently, UPTII (Underground Piping and Tanks Integrity Initiative) databases were gathered from multiple utilities to provide additional information on tank configuration and inspection methods. The combined dataset yielded a total of 143 tanks, from 43 plants, for analysis in this report. Further details of this information may be found in Appendix A.

2.1 Typical Tank Characteristics

From the survey responses and the UPTII database information a characterization of the tanks found at NPPs was developed. This section presents an overview of a typical tank at an NPP, as well as some common variations based on the detailed analysis of the combined survey and database information. Physical characteristics of the tank are covered, as well as contents. Figure 2-1 is a visual representation of this typical tank.

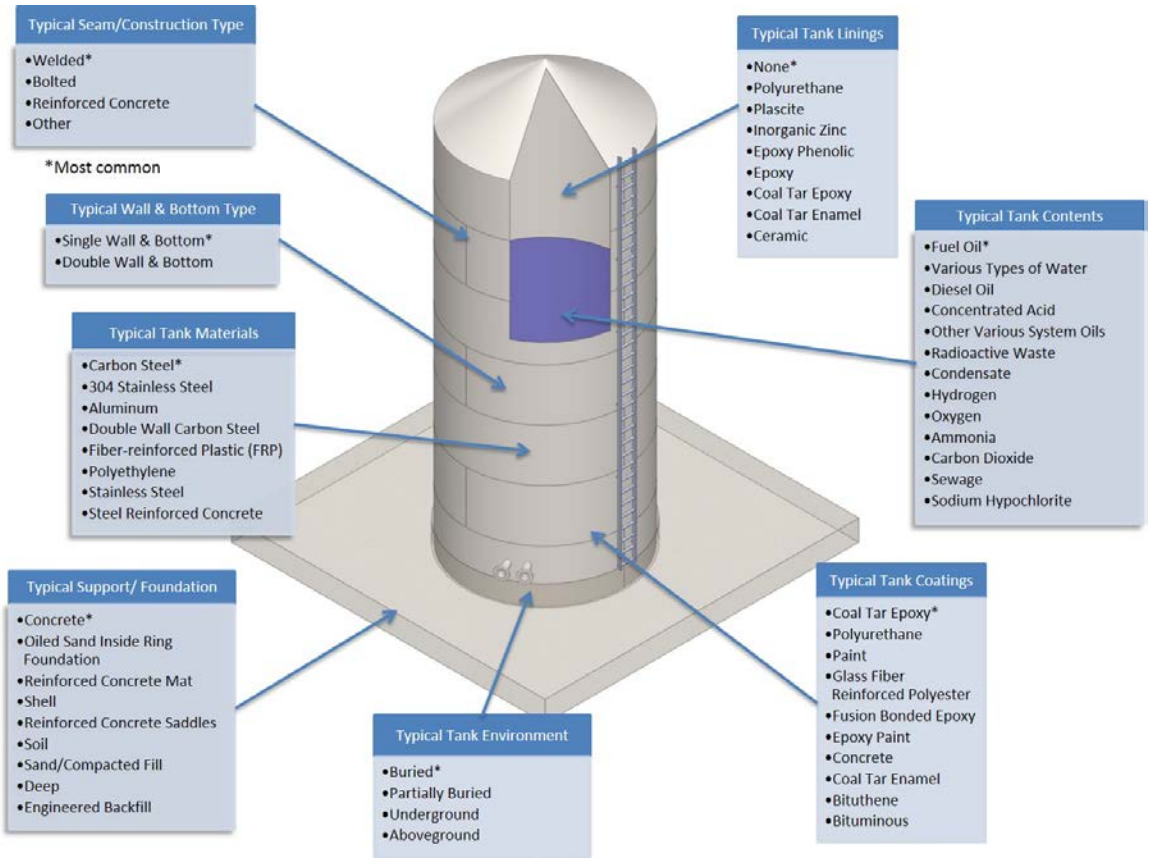

Figure 2-1
NPP Typical Tank

While both ASTs and USTs are found at NPPs, there is a preponderance of USTs. This is reasonable because, as mentioned previously, USTs include tanks that have some portion of their content volume contained below grade level (the EPA uses a cut-off of 10%). This means that as much as nearly 90% of the content volume of a tank could be above grade level and the tank would still be classified as an UST.

The vast majority of NPP tanks are welded seam construction and made of carbon steel (CS) material, followed by stainless steel (SS) in a distant second. The tanks are typically single-wall and single-bottom. Other materials of construction found include aluminum, polyethylene, fiberglass reinforced plastic (FRP), and steel-reinforced concrete, though these materials are much less common than CS and SS.

NPP tanks are most commonly supported on a solid concrete foundation or a concrete ring foundation filled with oiled sand.

The typical NPP tank is 30-40 feet tall and 10-20 feet in diameter, though there are a significant number of tanks with larger diameters (up to 50 feet or greater). Tank capacities vary from less than 10,000 gallons to over 500,000 gallons, with the typical tank having a capacity in the 50,000-100,000 gallon range.

Petroleum products are by far the most common content fluid in NPP tanks, primarily fuel oils. Next most common are various types of water (e.g., demineralized, water with tritium, wastewater, etc.). Other content types include various gases (e.g., hydrogen, oxygen, carbon dioxide), as well as various chemicals (concentrated acid, ammonia, sodium hypochlorite).

The majority of NPP tanks are externally coated, with coal tar epoxy and enamel coatings predominating. Other common coating types include epoxy paint, concrete, polyurethane, and simple paint.

In contrast, the majority of NPP tanks are NOT internally lined. Those with linings are typically lined with some form of epoxy. Inorganic zinc (similar to galvanizing) is also used as a liner in some tanks.

2.2 Inspection and Leak Data

Over 65% of the tanks included in the combined dataset were reported to have no history of leaks, with only 2% of responses with a known history of leakage. Inspection techniques used to evaluate the integrity of storage tanks were largely unreported (56% of the reported inspections indicated no response or unknown for the inspection type). Of those inspection techniques reported, similar numbers of inspections were reported for the following techniques:

- Ultrasonic Thickness (UT): 21 inspections
- Pressure Test: 28 inspections
- Visual Inspections (Visual OD, Remote Visual ID, and Visual): 36 inspections.

While the original intent was to use the data from the surveys and tank databases to inform the development of tank inspection guidelines, due to the limited identification of leakage, inspection techniques, and correlation of inspection findings this was not possible. Therefore, the development of this paper was focused primarily on guidelines developed by non-nuclear industries for the evaluation of storage tanks.

A detailed discussion of analyses completed on the survey responses and combined tank dataset is included in Appendix A for further information.

3
ABOVEGROUND STORAGE TANK INSPECTION

This section of the report pertains to inspection of Aboveground Storage Tanks (ASTs). Two relevant standards which have been developed primarily for the petroleum industry exist for AST inspection and a brief review of both of these documents is given here. These standards are *American Petroleum Institute Standard 653: Tank Inspection, Repair, Alteration, and Reconstruction*, which is discussed in Section 3.1, and *Steel Tank Institute Standard SP001: Standard for the Inspection of Aboveground Storage Tanks*, discussed in Section 3.2.

From the standards, damage to ASTs is most commonly caused or increased by the following mechanisms:

- Internal corrosion from stored product or water bottoms
- External corrosion from the environment (including mixed metals)
- High stress levels – static (hydrostatic or bulk pressure) and dynamic (vibration)
- Properties of stored product such as specific gravity, temperature, corrosivity, etc.
- Metal design temperatures at the service location of the tank are exceeded
- External roof live load, wind, snow, and seismic loadings
- Tank foundation, soil, and settlement conditions
- Distortions of existing tank
- Operating conditions such as filling/emptying frequency
- Failed corrosion controls in place to manage the same
- Impact due to neighboring construction or repair activities

3.1 Overview of American Petroleum Institute Standard 653

3.1.1 Introduction

The following is an overview of the American Petroleum Institute (API) Standard 653. The API 653 standard was developed by the petroleum industry to cover the minimum requirement for maintaining the integrity of in-service steel storage tanks and addresses inspection, repair, alteration, relocation, and reconstruction. API 653 relies on the design/construction principles in API 650 for welded storage tanks typically employed by the petroleum industry. However, owners can apply the API 653 guidance to non API-650 tanks but should include consideration of specific construction and operating details. The scope of this standard is limited to tank foundation, bottom, shell, structure, roof, attached appurtenances, and nozzles of the first flange, first threaded joint, or first welding-end connection.

This overview discussion focuses primarily on Section 6 of the API 653 standard concerned with specifics for component inspection and the suitability of an existing tank for continued service. The API 653 standard does address a broader range of concerns ranging from repairs to materials, design and alterations, welding, and dismantling/reconstruction.

3.1.2 The Inspection Process

API 653 is to be applied by organizations that maintain or have access to engineering and inspection personnel technically trained in tank inspections. Inspectors can obtain a certification as an "Authorized API 653 Inspector." A discussion of the process and qualifications for becoming an authorized inspector are included in API 653 Annex D.

API 653 provides discussion on the tank inspection process. Highlights from it will be further discussed below in this section. Annex C in API 653 contains sample checklists illustrating tank components and auxiliary items that should be considered for internal and external inspection of tanks. The checklists are also a good resource for a common format for recording inspection findings and an overview of what these checklists recommend inspecting is given in the proceeding sections.

Prior to conducting a tank inspection, an assessment of the potential hazards should be performed. Supporting API guidance is available in API 2015[4], API 2016[5] and API 2217A[6] that include safeguards for personnel health and safety, prevention of accidental fires and explosions, and the prevention of property damage. Due to comparable hazards, risks, and consequences, tank inspections at NPPs, preexisting industry guidance can aid in the development of inspection programs, procedures, scopes of work, and work instructions.

3.1.3 Inspector Qualifications

Per API 653, an authorized inspector is one who has been certified as an API Standard 653 inspector.

3.1.4 Inspection Types and Their Associated Inspection Intervals

API 653 approaches the inspection of tanks from four perspectives: routine inspections, external inspections, internal inspections, and inspections associated with cathodic protection (CP) surveys. The inspection approach is based on an assessment of anticipated corrosion rate and the influence of the corrosion control technique. The unique considerations associated with each are reviewed below. However, the interval between inspections of a tank should not conflict with any jurisdictional regulations.

[4] API 2015 Safe Entry and Cleaning of Petroleum Storage Tanks

[5] API 2016 RP Guidelines and Procedures for Entering and Cleaning Petroleum Storage Tanks

[6] Guidelines for Safe Work in Inert Confined Spaces in the Petroleum and Petrochemical Industries

3.1.4.1 Routine External Inspections

Monthly, up-close visual inspection from the ground is a potentially viable method to assess the external condition of the tank. This inspection may be done by owner/operator personnel, and can be done by other authorized inspectors. Personnel performing this inspection should be knowledgeable of the storage facility operations, the tanks, and characteristics of the stored product. Routine, in-service inspections include a visual inspection of the exterior surfaces of the tank. Evidence of leaks; shell distortions; signs of settlement; corrosion; and condition of the foundation, paint coatings, insulation systems, and appurtenances should be documented for follow-up action by an authorized inspector.

3.1.4.2 External Inspections

A visual external inspection is recommended at least every five years or according to the following formula, whichever is more frequent.

$$\frac{RCA}{4N}$$

Where,

RCA is the difference between the measured shell thickness and the minimum required thickness, in mils;

N is the shell corrosion rate, in mils per year.

Tanks may be in operation during this inspection. Insulated tanks need to have insulation removed only to the extent necessary to determine the condition of the exterior wall of the tank or the roof. Tank grounding system components such as shunts or mechanical connections of cables are also to be visually inspected.

External ultrasonic thickness measurements of the shell can indicate the integrity of the shell and be a means of determining a rate of uniform general corrosion while the tank is in service. The extent of such measurements shall be determined by the owner/operator. A five-year maximum inspection interval is recommended when the corrosion rate is not known. Corrosion rates may be estimated from tanks in similar service based on thickness measurements taken at an interval not exceeding five years. When the corrosion rate is known, the maximum interval for ultrasonic thickness measurements shall be the smaller of 15 years or the following equation. Internal inspection of the tank shell, when the tank is out of service, can be substituted for a program of external ultrasonic thickness measurements.

$$\frac{RCA}{2N}$$

The following is a list of components recommended to be inspected:

- Foundation
- Concrete ring
- Asphalt
- Sand condition

- Drainage systems
- Overall cleanliness
- Cathodic protection
- Shell condition
- Paint failure and corrosion
- Roof appurtenances
- Wind girder
- Nozzles
- Piping manifolds
- Sample station
- Heater
- Mixer
- Swing line components
- Deck plate components
- Gauge well
- Vents
- Vacuum breakers

3.1.4.3 Internal Inspections

Internal inspections are performed to ensure that the bottom is not severely corroded or leaking, and to identify and evaluate any tank bottom settlement. If the internal inspection is required solely for the purpose of determining the condition and integrity of the tank bottom, the internal inspection may be accomplished with the tank in-service utilizing various ultrasonic robotic thickness measurement and other on-stream inspection methods capable of assessing the thickness of the tank bottom, in combination with methods capable of assessing tank bottom integrity as described previously. Electromagnetic methods may be used to supplement the on-stream ultrasonic inspection. If an in-service inspection is selected, the data and information collected shall be sufficient to evaluate the thickness, corrosion rate, and integrity of the tank bottom and establish the internal inspection based on tank bottom thickness, corrosion rate, and integrity. See API 653 Annex B for additional information on the evaluation of tank bottom settlement issues and Annex C for a tank inspection checklist.

Initial inspections are performed within the first ten years of operation, unless one or more of the leak prevention, detection, corrosion mitigation or containment safeguards listed in Table 3-1 are present. Tank safeguards include: fiberglass-reinforced linings or internal thin-film coatings (per API 652); corrosion protection of the soil-side of tank bottoms installed, maintained and

inspected per API 651; release prevention barriers installed per API 650, Annex 1; or tank bottom corrosion allowances greater than 0.150 inches. The additional safeguards are cumulative. For example, for a ¼ inch bottom that has a Release Prevention Barrier and a fiberglass lining, the maximum interval would be determined by the following:

10 years (initial) + 5 years (fiberglass lining) + 10 years (Release Prevention Barrier) = 25 years

API 653 notes that initial inspection intervals for a tank without a Release Prevention Barrier should not exceed 20 years, and should not exceed 30 years for a tank with a Release Prevention Barrier.

Table 3-1
API - Time Added to Initial Inspection Interval

Safeguard Mechanism	Time Added to Initial Inspection Interval
Fiberglass-reinforced lining on product-side tank bottom, per API RP 652.	Five years
Installation of an internal thin-film coating, per API RP 652.	Two years
Cathodic protection on soil-side of tank bottom, per API RP 651.	Five years
Release prevention barrier, per API 650.	Ten years

After the initial inspection, the next inspection can be determined by measuring the corrosion rate and measuring the remaining tank bottom thickness. With these values known, the suitability of service and next inspection can be determined for the specific tank bottom configuration in question. API 653 gives the following method for calculating the minimum acceptable bottom thickness for the entire bottom or portions thereof.

$$MRT = RT - O(SP + UP)$$

Where:

MRT is the minimum remaining thickness, in inches, at end of interval *O*;

RT is the minimum remaining thickness, in inches, after repairs;

O is the in-service interval, in years, of operation;

SP is the maximum rate of corrosion, in inches per year, not repaired on the top side. *SP* = 0 for coated areas. In order to use *SP* = 0, the expected life of the coating should exceed or equal *O*.

UP is maximum rate of corrosion, in inches per year, on the bottom side. To calculate corrosion rate, use the minimum remaining thickness after repairs and assume a linear rate based on the tank age. *UP* is zero for areas having cathodic protection.

Depending on whether the tank bottom does or does not have spill protection systems and leak detection systems, or a reinforced lining, will dictate the minimum acceptable bottom plate thickness at the next inspection. Refer to API 653 for the values specific to the aforementioned tank bottom designs.

It should also be noted that tanks with annular plate rings typically require greater minimum thicknesses. These values are based upon stress considerations and depend upon whether the tank contains products greater than or less that one. The acceptable values for tanks containing products less than one can be found in API 653, and the values for tanks having product with specific gravities greater than one can be found in API 650.

It is advisable to have history of the service of a given tank or a tank in similar service (preferably at the same site) available so that complete inspections can be scheduled with a frequency commensurate with the corrosion rate of the tank. Factors to consider when determining storage tank inspection include:

- Nature of product stored
- Results of visual maintenance checks
- Corrosion rates
- Corrosion prevention systems
- Impact and natural disaster events
- Risk of air and water pollution
- Leak detection systems
- Changes in operating model
- Jurisdictional requirements
- Existence of release prevention systems and leak detection systems
- Fabrication method and materials of construction

On-stream, nondestructive evaluation methods can also be considered when establishing inspection frequencies.

Additionally, the following are recommended to be inspected during an internal inspection.

- Tank cleanliness and safety
- Exterior appurtenances
- Bottom interior surfaces
- Shell seams/plates
- Roof components
- Hatches
- Vents
- Toroidal assembly

- Rim-mounted secondaries
- Vacuum breakers
- Drainage systems
- Autogauge systems
- Common tank appurtenances
- Nozzles
- Diffusers
- Swing lines
- Heater racks
- Mixer wear plates
- Access structures
- Stairways
- Rolling ladders

3.1.4.4 Risk Based Inspection

The results of a Risk Based Inspection (RBI) assessment can be used to establish a tank inspection strategy that defines the most appropriate inspection methods, appropriate frequency for internal, external, and in-service inspections, and prevention and mitigation steps to reduce the likelihood and consequence of tank leakage or failure. An RBI assessment consists of a systematic evaluation of both the likelihood of failure and the associated consequences of failure, in accordance with API RP 580. The RBI assessment thoroughly documents and clearly defines all factors contributing to both likelihood and consequence of tank leakage or failure. The RBI assessment is to be performed by a team at intervals not to exceed 10 years or more if warranted by process equipment or consequence changes.

The RBI methodology, validation process, and a collection of tank specific likelihood factors to consider in addition to those outlined in API 580 are included in Section 6.4.2.2.2 of API 653. The RBI validation should be performed by an entity external to the RBI assessment team. It is not recommended that tanks be run to tank-bottom failure or operating tanks indefinitely with known or suspected bottom leaks.

3.1.4.5 Cathodic Protection Surveys

Where exterior tank bottom corrosion is controlled by a cathodic protection system, periodic surveys of the system shall be conducted in accordance with API 651. The owner/operator should review the survey results and evaluate/troubleshoot conditions indicating insufficient protection by the CP system.

3.1.5 Recommended Recordkeeping

Inspection records form the basis of a scheduled inspection/maintenance program. If records do not exist for older tanks, judgment on inspection intervals must be based on experience with tanks in similar services. API 653 recommends that owner/operators maintain a complete record file consisting of three types of records: construction records, inspection history, and repair/alteration history. *Construction records* may include nameplate information, drawings, specifications, construction completion report, and any results of material tests and analyses. Records for the *inspection history* include all measurements taken, the condition of all parts inspected, and a record of all examinations and tests. A complete description of any unusual conditions shall also be included, with recommendations for correction of details which cause the conditions. This file should also contain corrosion rate and inspection interval calculations. *Repair/alteration history* includes all data accumulated on a tank from the time of its construction with regard to repairs, alterations, replacements, and service changes. These results should include the results of any experiences with coatings and linings. Recommended reporting requirements are described in API 653 Section 5.5.2.

3.1.6 Establishing Suitability for Service

API 653 provides evaluation guidance to establish acceptance criteria for the determination of suitability for continued use. Guidance is provided as a function of the specific tank component:

- Tank Roof Evaluation (API 653, Section 4.2)
- Tank Shell Evaluation (API 653, Section 4.3)
- Tank Bottom Evaluation (API 653, Section 4.4)
- Tank Foundation Evaluation (API 653, Section 4.5)

In each section, specific and detailed information is provided for the disposition of each major sub-component. Charts, tables, and equations are provided to establish the acceptance criteria and support the decision making process.

Tank Roof Evaluation – Corrosion of roof plates is generally due to corrosion from operating environment. Roof plates corroded to an average thickness of less than 0.09 in. within any 100 $in.^2$ area of roof plates, or roof plates with any though holes, is recommended to be replaced. Roof supports are recommended to be inspected with a method deemed acceptable by the responsible inspector. In the case of floating roofs, areas of roof plates and pontoons which exhibit punctures or cracking shall be repaired or replaced. Additionally, roof appurtenances such as ladders, drainage systems, and venting systems are to be evaluated for needed repairs or replacements.

Tank Shell Evaluation – Shell corrosion can occur in many forms and varying degrees of severity and may result in a generally uniform loss of metal over large surface areas or localized regions. Pitting does not normally represent a significant threat to the overall structural integrity of a shell unless present in a severe form with pits in close proximity to one another. Equations are provided to determine when widely scattered pits may be ignored. Detailed procedures are provided for determining the minimum shell thickness suitable for continued operation. This includes guidance on measuring maximum pit depths in complex corrosion morphologies and methods of hydrostatic testing and welded joint efficiencies.

Tank Bottom Evaluation – Historical causes of tank bottom failures are reviewed. Such failures include internal pitting, corrosion of weld joints, stresses from roof supports and shell settlement, underside corrosion, poor drainage, uneven settlement, and inadequately supported sumps. Leak detection/testing and other release mitigation measures, such as release prevention barriers, soil vapor monitoring, and chemical markers are also discussed.

Tank Foundation Evaluation – Principle causes of foundation deterioration are settlement, erosion, cracking, and deterioration of concrete initiated by calcination, attack by underground water, attack by frost, and attack by alkalis and acids.

3.2 Overview of Steel Tank Institute (STI) Standard SP001

The following is a review of Steel Tank Institute Standard SP001, "Standard for the Inspection of Aboveground Storage Tanks." This standard provides inspection and evaluation criteria to determine the suitability for continued service of ASTs. The criteria outlined within the standard are minimum requirements. Where applicable, local, federal, and state laws should be reviewed to determine the more stringent criteria to follow. The standard applies for ASTs storing stable, flammable, and combustible liquids which operate in ambient temperatures up to 200°F.

To provide a baseline, tank components, primary tanks (tank which is direct contact with stored liquid), secondary tanks (outer wall of a double-wall AST), support structures (foundation, anchors, and so on), alarms, appurtenances, vents, release prevention/spill control systems should be inspected.

3.2.1 Inspection Methods

The following methods are recommended for inspection.

1. **Continuous Release Detection Methods (CRDM)** – CRDM are a means of passively detecting a release of liquid. Examples of such systems are release prevention barriers, secondary containment ASTs, and elevated ASTs.
2. **Leak Testing Methods (LTM)** – Examples of LTM technologies are gas pressure decay, soap bubble testing, gas tracers, solid tracers, mass measurement, level measurement, and hydrostatic testing.
3. **Magnetic Flux Leakage** – This method is commonly used to inspect ferromagnetic ASTs floors for purposes of detecting wall thinning. This technique is based upon magnetizing the AST floor. The detected changes in magnetic flux permeating the floor are associated with changes in floor thickness.
4. **Periodic Visual Inspection** – Aided or unaided visual inspection of the tank.
5. **Ultrasonic Thickness (UT) testing and Ultrasonic Scans (UTS)** – Ultrasonic Thickness testing is a method where a sound wave is generated and reflects between the front- and back-wall surface boundaries. The time of these return trips of the wave are recorded, and with a known ultrasonic velocity in the material, the thickness can be calculated. Ultrasonic scans can be processed to create color map images of the component thickness and can cover a large range of surface area. UTS is usually preferred when available.

7. **Magnetic Particle Testing (MT)** – Technique performed by magnetizing the component being investigated, followed by application of magnetic particles to the surface. Regions where magnetic particles gather indicate regions of flux leakage which are associated with surface and subsurface flaws such as cracking.
8. **Dye Penetrant Testing** – Low surface-tension fluid is applied to surface of component. The low surface tension of the fluid allows it to penetrate into thin surface defects. Developer is then applied and exposed to ultraviolet or white light and colored regions indicate regions where defects may exist, such as surface cracks.
9. **Radiation Testing** – Component is irradiated with X-rays or a radiation source. The amount of radiation emitted on the other side of the component is measured and used to create an image. Variations of emitted light can be used to determine thickness, density, and composition of the component.

3.2.2 Inspector Qualifications

Certified inspector qualifications are recommended by the Steel Tank Institute to be certified by the American Petroleum Institute 653 *Authorized Inspector Certification with STI SP001 Adjunct Certification* or by the Steel Tank Institute *Certified SP001 Adjunct Certification*. It is recommended that the qualifications of the inspector should be in accordance with American Society for Nondestructive Testing (ASNT) document SNT-TC-1A. These written practices pertain to magnetic particle, radiographic, ultrasonic, magnetic flux leakage, and dye penetrant testing methods.

3.2.3 Inspection Interval

Per SP001, the inspection schedule should be determined by the owner, and is dependent upon AST type, size, installation, corrosion rate, and previous inspection history. ASTs are categorized into the following levels.

1. ASTs with spill control and with CRDM
2. ASTs with spill control but without CRDM
3. ASTs without spill control and without CRDM

Further details of these classifications are provided in SP001. AST interval designations are given by periodic external inspections, formal external inspections, formal internal inspections, and leak test inspections. In short, the intervals are dependent upon tank capacity and the tank configuration being one from the following bulleted list. It is important to identify the tank configuration and correlate it with frequency of the tank inspection.

- Single wall tank in contact with ground
- Single wall tank not in contact with ground
- Elevated tank
- Double bottom tank

- Tank has a RPB
- Tank has overfill protection
- Tank is resting on concrete

3.2.4 Periodic AST Inspections

It is important that repair, alteration history, and special conditions are reviewed prior to AST inspection. It is recommended that the inspector is to complete *STI SP001 AST Record* and *STI SP001 AST Monthly Inspection Checklist* during periodic AST inspections.

3.2.5 Formal External Inspection (FEI) Guidelines

It is important that fabrication of the AST is compared to industry standards and that repair history, original shell thickness, alteration history, and special conditions are reviewed prior to performance of AST Formal External Inspections. To this end it is also helpful to identify the system type of the secondary spill containment systems. During this inspection, it is recommended that the general condition of the foundation, supports, containment area, piping, valves, vents, tank level gauges, and coatings of the AST be inspected. STI recommends that thickness measurements are made in areas where no corrosion or pitting has occurred to determine a minimum shell thickness. Additional requirements are made depending upon whether the tank is a horizontal AST, vertical AST, rectangular AST, double-wall/double-bottom AST, and/or an insulated AST. Each of the aforementioned AST types require inspection of shell, shell attachments, and welds for signs of buckling, distortion, forms of corrosion, and signs of stress. UT readings are also recommended for areas which are accessible without entry to the AST. For Vertical ASTs, it is recommended that roof structures be inspected for corrosion, standing water, and that UT readings be taken of these structures. Additional requirements for double-wall ASTs include checking that leak detection equipment is properly operating. For insulated ASTs, it is recommended that insulation be removed in areas where damage to insulation is suspected (e.g., signs of moisture or mold are observed).

3.2.6 Formal Internal Inspection (FII) Guidelines

When Formal Internal Inspection is performed, it is recommended in Section 8.0 of SP001 that a Formal External Inspection is also conducted. In the case of elevated ASTs where all external surfaces are exposed, an internal inspection may be forgone if a suitable method such as UTS is performed from the exterior.

Visual inspection of all internal appurtenances, welds, and damage is recommended. If necessary, the inspection of welds with the use of magnetic particle may be beneficial and is recommended. For questionable welds, vacuum box testing is recommended to ensure there are no leaks in weld regions.

It is also suggested that the complete inspection of the AST floor occurs by UTS, UT, MFL, or other suitable inspection method which is capable of determining the underside floor condition. It is preferred that scanning methods such as UTS and MFL be used to obtain complete coverage

of the floor due to random corrosion characteristics of metal in contact in the ground. If scanning of the tank cannot be performed because it is not practical, it is recommended that UT measurements are taken in at least 15 spots per square foot of the shell area which is contacting the ground.

When performing LTMs, it is recommended that Steel Tank Institute Recommended Practice R912 be consulted, and for portable containers it is recommended that DOT Sections 49 CFR, and part 178 – 49 CFR Subpart O and 49 CFR 180.605, or equivalent, be consulted.

3.2.7 Suitability for Continued Service

Criteria for continued service are given within the standard and are dependent upon AST Category (Category 1, 2, or 3). The category of the tank is based on the damage or harm which would be likely if a leak were to occur with the categories of 1, 2, and 3 indicating an increase in damage or harm (i.e., Category 2 would be more harmful than Category 1, etc.) For Category 2 and Category 3 ASTs, it is recommended that the tank be removed from service and repaired or replaced if a square foot of the tank shell thickness has been reduced to less than 75%. For Category 2 ASTs, if any point of the shell is reduced to less than 50% of the original shell thickness, it should be removed from service and repaired or replaced. For Category 1 ASTs, if a square foot of the shell thickness has been reduced to less than 50% of the original shell thickness, or if any one point is reduced to less than 25% of the original thickness, the AST is to be removed from service and repaired or replaced. In cases where removal from service for repair or replacement is required, the standard recommends review of *Steel Tank Standard Institute SP031* for further instructions. In the event of fire, natural disaster, excessive settlement, overpressure, or cracking, evaluation is necessary by a qualified engineer as to whether external or internal inspections are required for continued service.

3.2.8 Inspection of Field Erected ASTs

According to STI SP001, field-erected tanks (tanks which are constructed on-site at the facility) that are greater than 30 ft. in diameter or have height exceeding 50 ft. should be inspected according to an appropriate field-erected tank standard (no specific field erected tank standards are recommended). Additionally, STI SP001 recommendations for field-erected ASTs are only applicable to ASTs which meet one or more of the following criteria[7]:

1. Welded and flat-bottom, cone-up, or cone-down design;
2. Fabricated with full-fusion, butt-welded shells and with lap-welded or butt-welded bottom plates; and/or
3. Fabricated with a shell course thickness of less than ½ inch and with original nominal bottom thickness plates equal to ¼ inch and built to a nationally recognized standard.

For field-erected ASTs, of Category 1, 2, and 3, FEIs are recommended to be performed every five years and FIIs every ten years. Visual inspections are to be performed in the same manner as other ASTs. According to STI, proper determination of corrosion rates can extend the length

[7] While it is not clear from STI SP001, it is assumed that meeting any one of the criteria is sufficient, as opposed to meeting all three criteria.

between internal inspections but it cannot exceed 30 years for a Category 1 tank, 20 years for a Category 2 tank, and 10 years for a Category 3 tank. In all cases, tank thicknesses which are below 0.1" are unacceptable.

3.2.8.1 Inspections

Additional outlines for determining the minimum shell thickness are given. The following is given as a means to determine the minimum shell thickness which is acceptable. It should be noted that SP001 reports that t_{min} should not be less than 0.1 in. for any tank course.

$$t_{min} = \frac{(H-1)DG}{10{,}000}$$

Where:

t_{min} is the minimum acceptable average thickness, in inches, for each course as calculated from the above formula.

H is height from the bottom of the shell course under consideration to the maximum liquid level when evaluating an entire shell course, in feet.

D is nominal diameter of tank in feet.

G is the largest specific gravity of the contents.

One method of determining the interval between FIIs required for the tank bottom assessment is (Note: corrosion rates are assumed to be constant for these calculations):

$$MFIII = \frac{\min\left(RT_{bc}, RT_{ip}\right) - MRT}{(StPr + UPr)}$$

Where:

MFIII is the maximum formal internal inspection interval (years per internal inspection).

RT_{bc} is minimum remaining thickness from bottom side corrosion after repairs.

RT_{ip} is minimum remaining thickness from internal corrosion after repairs.

MRT is minimum allowable remaining tank bottom thickness at the end of inspection interval.

StPr is the maximum rate of corrosion not repaired on the top side. For areas which are coated this value is considered to be zero.

UPr is the maximum rate of corrosion on the bottom side.

3.2.9 Overview of STI SP001 AST Recordkeeping and Inspection Checklist

3.2.9.1 Recordkeeping

Per STI SP001, the following information should be documented for appropriate recordkeeping regarding aboveground storage tanks.

1. Owner, facility, and installer information
2. The following tank specifications:
    a. Design
    b. Manufacturer
    c. Contents
    d. Construction date
    e. Repair history
    f. Dimensions
    g. Capacity
    h. Containment
    i. Construction and associated systems (bare steel, cathodic protection and type, coated steel, concrete, plastic/fiberglass, double bottom, double wall, liner, etc.)
    j. CRDM type and installation date
    k. Release prevention barrier type and installation date
    l. Monthly Inspection Checklist (retain each for at least 36 months)
    m. Annual Inspection Checklist (retain each for at least 36 months)
    n. Certified inspection reports (retain all for the life of the AST)
    o. Portable Container Monthly Inspection Checklist (retain each for at least 36 months)

3.2.9.2 Inspection Checklist

The STI AST annual visual inspection checklist for AST recommends inspecting the following:

- Tank containment components
- Tank foundation and supports
- Cathodic protection system
- Tank shell, head, and roof
- Vents
- Valves

- Leak detection equipment
- Spill containment system
- Strainer
- Filters
- Flame arrestors
- Liquid level equipment
- Overfill equipment
- Insulation
- Electrical wiring
- Labels and tags

The STI monthly inspection checklist for portable containers recommends making the following inspections.

- Verify the AST is within the designated area.
- Verify the area is free of debris, spills, and fire hazards.
- Verify there is no water in outdoor secondary containment.
- Inspect egress pathway condition.
- Check for signs of leaks.
- Look for container distortions.

3.4 Flow Charts for Aboveground Storage Tank Inspections

3.4.1 Primary Flow Chart

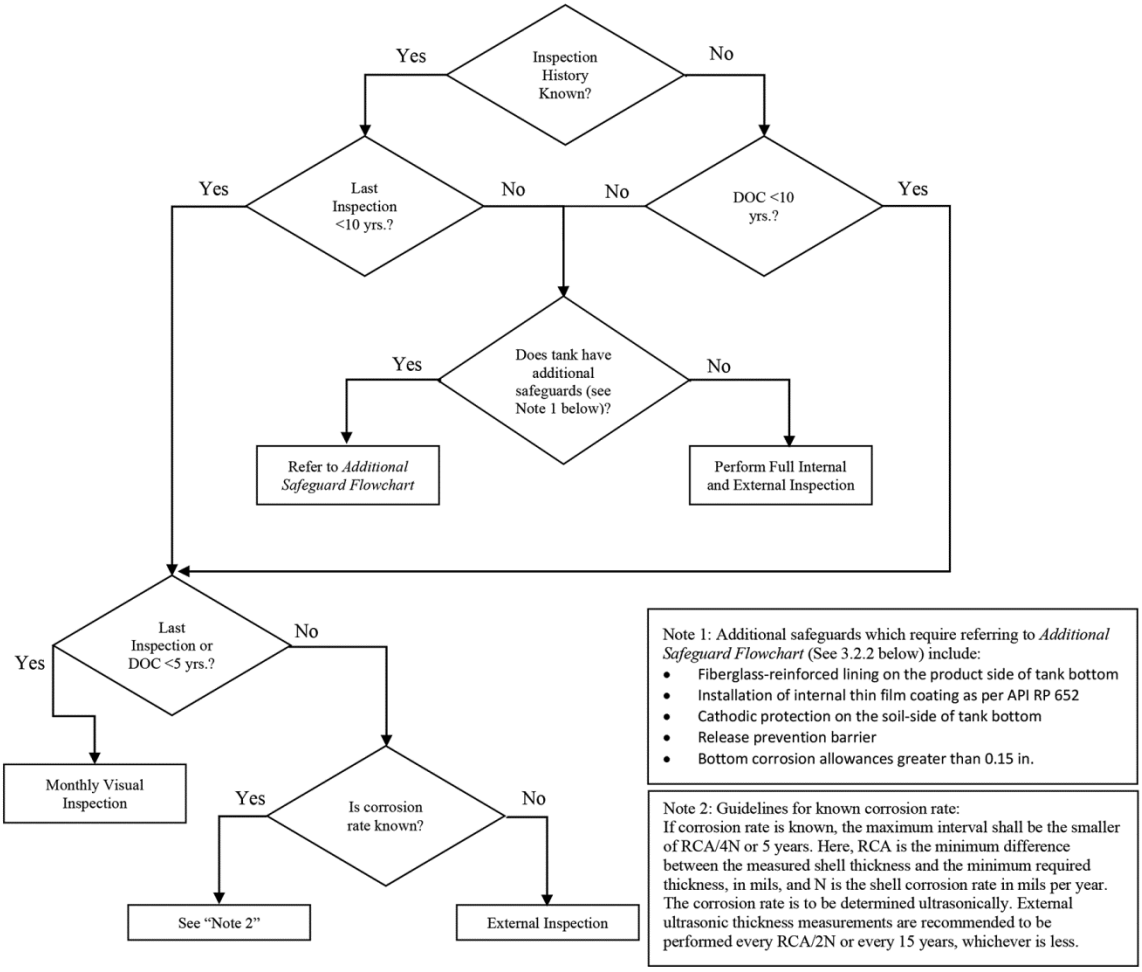

Figure 3-1
AST Inspection Flow Chart, Tank Inspection History

3.4.2 Additional Safeguard Flow Chart

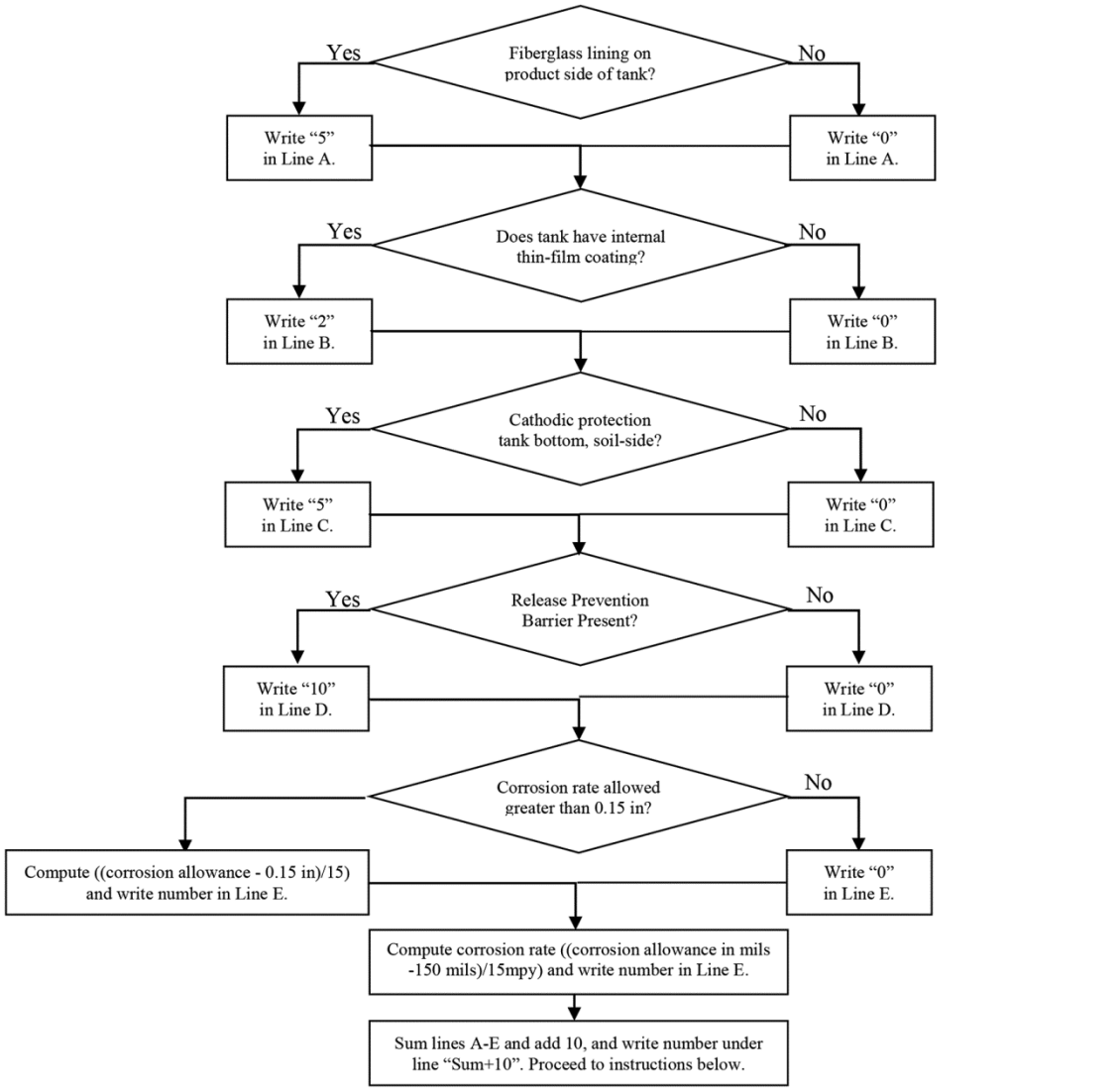

Figure 3-2
Additional Safeguard Flow Chart

4
UNDERGROUND STORAGE TANK INSPECTION

The monitoring of the structural health of underground storage tanks (USTs) is significantly different than what is typically practiced for ASTs. USTs are heavily regulated on both federal and, often, state levels. Newly constructed USTs must be built with several levels of secondary safeguards and corrosion protection systems. When considering what practice to implement for health monitoring of USTs, plant operators should consult and conform to the mandates of the federal and state governments. A list of contacts for each state can be found at the EPA's website[8] and a list of regulations for each state can be found at the Tanknology website[9]. The following provides a general outline of the federal regulations. They are described in "Musts for USTs: A Summary of Federal Regulations for Underground Storage Tank Systems," as well as a few additional practices recommended by the Petroleum Equipment Institute in Appendix B, which are to be performed on a daily, monthly, and yearly basis. (Note: these checklists can be found on PEI's website.) The following sections will provide an overview of the federal regulations provided by the Environmental Protection Agency (EPA) and will cover topics such as leak detection, monitoring, warning signs, etc. This document assumes the reader is familiar with the requirements for UST construction which are given in Code of Federal Regulations, 40 CFR Part 280.

It is worth noting here that there is a prevailing theme between the state and federal regulations. USTs are required to be constructed with at least one secondary containment system. Most regulations do not include giving direction for active, preventive-damage, health monitoring utilizing technologies such as UT, MFL, etc., as is more common with ASTs. Instead, monitoring of USTs is more focused on rapid leak detection followed by quick repair, replacement, or decommissioning of the UST. This does assume that other regulations governing UST integrity, namely cathodic protection, have been installed, monitored, and maintained such that long-cycle failures are of lower risk.

8 http://www.epa.gov/oust/states/statcon1.htm

9 http://www.tanknology.com/ust-state-regulations.html

4.1 Overview of Environmental Protection Agency Document "Must for USTs"

4.1.1 Leak Detection

As a requirement of Code of Federal Regulations 40 CFR Part 280, all USTs must be constructed or retrofitted with leak detection systems. Each leak detection system must meet all of the following three basic requirements.

1. The leak detection system can detect a leak from any portion of the tank or its piping that routinely contains petroleum.
2. The leak detection system is installed, calibrated, operated, and maintained in accordance to the manufacturer's instructions.
3. The leak detection system meets performance requirements described in Sections 280.43 and 280.44 of the federal regulations – 40 CFR Part 280.

For monitoring the leak detection system, the federal government mandates monthly monitoring methods (See Section 4.1.1.1 below) and also permits a temporary monitoring method.

4.1.1.1 Monthly Monitoring Methods

The following is a list with a brief description of the monthly monitoring methods which may be employed to meet regulations. According to the EPA at least one of these methods are to be used.

1. **Interstitial Monitoring:** This method detects leaks in the space between the UST and second barrier. The regulations describe general performance requirements for interstitial monitoring with double-walled USTs, USTs fitted with internal liners, and USTs using interception barriers.
2. **Automatic Tank Gauging Systems:** This method uses automated processes to monitor product level and inventory control.
3. **Monitoring for Vapors in the Soil:** This method samples vapors in the soil surrounding the UST. Leaked petroleum produces vapors that can be detected in the soil void space. The regulations describe several requirements for using this leak detection method. For example, this method requires using soils with high void ratios in the backfill and locating the monitoring devices in these soils near the UST system.
4. **Monitoring for Liquids in the Groundwater:** This method monitors the groundwater table near a UST for the presence of released free product on the water table. Monitoring wells near the UST are checked frequently to see if petroleum can be detected. The regulations describe several requirements for use of this method. For example, this method cannot be used if the water table is more than 20 feet below the surface of the ground.

5. **Statistical Inventory Reconciliation:** In this method, a trained professional uses computer software to conduct a statistical analysis of inventory, delivery, and dispensing data, which must be supplied regularly.
6. **Other Methods Approved by the Regulatory Authority:** If other methods can be shown to work as effectively as the methods described above for leak detection, these alternative methods can be approved by the regulatory authority.

4.1.1.2 Alternative Leak Detection Methods

Instead of using the six methods mentioned above, inventory control can be combined with tank tightness testing, but only for ten years after the initial tank construction. Inventory control involves making daily measurements of tank contents and recording deliveries and amount pumped. Daily and monthly calculations can be used to determine leakage of the tank. Tank tightness testing usually requires taking the UST out of service while changes in level or volume over time are measured. The tank tightness test is mandated to be performed at least every five years. After ten years, one of the monthly monitoring methods discussed above must replace this method.

4.1.1.3 Tank Gauging Leak Detection for Small Tanks

Tanks with capacity equal to or less than 2,000 gallons may be allowed to use manual tank gauging as a leak detection method. Depending on tank capacity, this method may be utilized by itself or in combination with tank tightness testing. This method involves keeping the tank undisturbed for at least 36 hours each week. During this time, the volume of the tank contents are measured twice at the beginning and twice at the end of the test period. Manual tank gauging can be used as the sole method of leak detection for the life of the tank for tanks up to 1,000 gallons, inclusive. Tanks between 1,001 and 2,000 gallons can use this method only in combination with tank tightness testing. This combined method is only valid for ten years following tank installation. More information on this method can be found in the EPA booklet, *Manual Tank Gauging for Small Underground Storage Tanks.*

4.1.1.4 Additional Leak Detection for Piping

According to the EPA, pressurized piping must meet the following requirements:

1. Piping must have devices that automatically shut off or restrict flow or have an alarm which indicates a leak.
2. An annual tightness test must be conducted on the piping of using one of the following monthly methods: interstitial monitoring, vapor monitoring, groundwater monitoring, statistical inventory reconciliation, or other approved methods.

If the UST has suction piping, the leak detection requirements are type-dependent. Below-grade piping operating at less than atmospheric pressure is sloped so that the piping contents will drain back to the tank if suction is released does not require leak detection. If the piping does meet this requirement, it must have leak detection that is performed using one of the monthly methods previously mentioned or with tightness testing performed triennially.

4.1.1.5 Signs of a UST Leak and Appropriate Action

A leak may be suspected when the following are observed:

1. Unusual operating conditions, such as erratic behavior at the dispenser.
2. Results from leak detection monitoring and testing indicate a leak.

Should a leak be detected, the appropriate regulatory authority should be contacted and the leak reported. Upon contacting the appropriate authority, it must be determined whether or not the suspected leak is an actual leak. This can be performed from the following steps:

1. Conduct tightness testing of the entire UST system.
2. Check the site for additional information on the presence and source of contamination.

If a leak is confirmed, the EPA has identified several actions to take which may be considered sequential and/or overlapping. The actions have been categorized by the EPA as short-term and long-term but, none the less, time is of the essence and swift attention should be given to the confirmed leak. The following is a list of the short-term actions. It should be noted that the majority of these steps imply leakage to the surrounding soil in which the tank is contained. However, like-kind consideration and immediate attention should also be performed for indication of leaks in interstitial area surrounding the inner wall of a UST.

1. Contain the release.
2. Report the release to the appropriate regulatory authority within 24 hours.
3. Make sure the release poses no immediate hazard to human health and safety by removing explosive vapors and other fire hazards. Local fire departments should be able to assist in this task.
4. Remove product from the UST system to prevent further release.
5. Investigate how the product has moved and recover it. A progress report to the regulatory authority is required within 20 days.
6. Determine extent of contamination in soil and groundwater.

For long-term actions:

1. Develop and submit a Corrective Action Plan that shows how it has met requirements set forth from the regulatory authority.
2. Ensure the steps developed by the regulatory authority are taken.

4.1.2 Recordkeeping

The government requires that records are kept and can be provided to an inspector to verify the facility meets what is required. The following are required.

1. Records of leak detection performance and maintenance. These include:
    a. Monitoring results of the previous year and most recent tightness tests;
    b. Copies of performance claims provided by leak detection manufacturers; and
    c. Records of maintenance, repair, and calibration of on-site leak detection equipment.
2. Records of required inspections and tests of the corrosion protection system.
3. Records showing repaired or upgraded UST system was properly repaired or upgraded.
4. For at least three years after closing a UST records must be kept of the site assessment results required for permanent closure.
5. Records must be kept which document financial responsibility, which are outlined in the EPA document *Dollars and Sense*.

5
REVIEW OF NDE TECHNOLOGIES FOR TANK INSPECTION

The range of technology used for the nondestructive examination of storage tanks varies greatly, from the very basic application of traditional NDE methods by human inspectors located inside or outside of the tank to complex remotely operated or autonomous scanners that are capable of delivering NDE technology without the need to empty the tank. The newest category of NDE technology for storage tanks enables long-term monitoring of in-service storage tank floors for damage growth using sensors mounted on the outside portions of the tank. EPRI has published several documents that address some of the available NDE methods and technologies available for storage tank inspections. These include: *Nondestructive Evaluation for Tanks and Concrete Liners* (Product ID: 3002000462) and *Inspection Methods for Tanks and Containment Liners* (Product ID: 1025215).

There are many factors involved in choosing a suitable technology for the inspection of a storage tank. Several of these factors include:

- Tank location/accessibility (below- or aboveground)
- Area(s) to be inspected
- Likely damage mechanisms to be detected
- Sensitivity, resolution, accuracy, and reporting requirements
- Material(s) used for construction
- Presence of other structural features (e.g., liners, seams, rivets)
- Consequences of failure emphasizing accuracy/reporting targets
- Tank contents
- Cost and risk of contamination

To assist in the identification of appropriate NDE technologies for accomplishing specific tank inspection objectives, a table has been included in Appendix D that provides an overview of commercial NDE technologies that are oriented toward storage tank inspections. In this table, the NDE technologies are arranged into three primary categories according to how they are typically applied:

1. Manual
2. Robotic/Autonomous
3. Structural Health Monitoring

The table also includes information on the NDE method(s) employed by each technology, a brief description, the tank area(s) of applicability, the required service status of the tank for application of the technology, and some general capabilities and limitations of each of the technologies. This list should not be thought of as comprehensive but rather as a starting point for understanding what technologies are available and potentially appropriate for application to a specific component or portion of the tank. To gain a comprehensive understanding of the appropriateness of one of these technologies for a specific application, the reader is referred to the Original Equipment Manufacturers (OEMs), technology vendors, and the EPRI documents referenced at the beginning of this section.

The following three sections provide brief descriptions of each of the categories used to classify the technologies included in the table in Appendix D.

5.1 Manually Applied NDE Technologies for Tank Inspection

As implied by the category title of the table, this technology category is intended to include any NDE technology that requires a human operator to be in direct contact with the inspection equipment. The equipment is typically hand-held and/or manually manipulated by the user. The user will generally need direct access to the area to be inspected, which typically means that, for the inspection of internal tank components, the tank needs to be removed from service and emptied. For tanks containing water, divers may be employed in some situations to apply manual methods without dewatering.

Some manual NDE technologies can be applied from the exterior of the storage tank without the need to empty the tank, but these methods are typically only capable of examining accessible areas of the tank shell. As indicated in the technology table (See Appendix D), there are a few manual NDE technologies that can be applied from the tank exterior that have the potential to provide some information about the outer rim of the tank floor. These technologies utilize ultrasonic guided wave techniques and, therefore, can only provide qualitative information, currently.

Several of the other manually applied NDE technologies are also only capable of producing qualitative results, so one should consider whether or not quantitative information is required when selecting an appropriate NDE technology. There are trade-offs to be considered when considering the application of quantitative versus qualitative methods. For example, it may be possible to obtain some qualitative information about the condition of the tank floor from outside of the tank, which means the tank does not need to be removed from service and emptied. If quantitative information is still needed to support engineering analyses, qualitative methods may not provide the level of detail required, but could provide indicators of corrosion risks that allow an owner to justify scopes and costs for more comprehensive evaluations.

A majority of the manually applied NDE technologies included in the provided table are intended for the inspection of the structural material for flaws. Leak detection methods are also available that may help to identify leaks in the tank structure and/or tank peripherals, such as valves, drains, etc. These technologies operate by listening for acoustic noise being emitted by the leaks or, alternatively, by introducing a detectable tracer of some kind (e.g., dye, low-

concentration gases, or even a helium atmosphere) within the tank and then utilizing detectors to examine areas on the outside of the tank. For the latter method, significant planning in how to introduce, discharge, and detect the tracer is required and can vary greatly by structure, location, contents, and targets.

5.2 Robotic/Autonomous NDE Technologies for Tank Inspection

This category of technology generally refers to NDE technology that is delivered to the area-of-interest via a robotic device. It is intended to include both robotic technologies that are remotely operated by a human and those that are capable of scanning autonomously. The technologies in this category that have been included in the table in Appendix D are commercially marketed for tank inspection applications and consist of packaged robotic NDE solutions. There are many robotic devices that do not come with specific NDE technologies integrated with them but that are capable of delivering NDE technology. Several examples of capable robotic systems have been included in Appendix D as examples; however, due to the large number of robotic delivery systems on the market and the rate at which new robotic technology is being introduced, it is not reasonable or valuable to provide an exhaustive list. Therefore, the inclusion or omission of any particular robotic delivery system should not be taken as an indication of superiority or inferiority, respectively.

For this category of technology, it is useful to differentiate between the robot technology and the NDE technology as, in several cases, the robotic platform may be capable of delivering a multitude of NDE technologies, either simultaneously or individually. The primary advantage to using a robotic technology is that, in most cases, it does not require the contents of the tank to be emptied. It should also be noted that many of the available tank inspection robots are intended for tank floor inspection only, though some are capable of inspecting the shell, as well.

As with the selection of any NDE technology, specific attention should be given to the likely degradation mechanism of the tank-of-interest as many of the robotic delivery systems are intended for wall thickness mapping and are not capable/suitable for the detection of weld cracking, for example. There are also robotic options for weld inspection, which are similarly incapable or not well-suited for thickness mapping.

5.3 Structural Health Monitoring Technologies

Nondestructive monitoring technologies, sometimes referred to as Structural Health Monitoring (SHM) technologies, comprise the newest category of NDE technology for storage tanks. These technologies can be differentiated from traditional NDE methods in that sensors are installed on the structure and are used to monitor the structure over some length of time, usually months to years, but in some cases less.

Another significant differentiation between traditional NDE and SHM for storage tanks is that, while NDE provides instantaneous information about the current damage state of the structure, SHM methods only provide information regarding changes in the damage state since the time of installation. For example, the SHM technologies included in Appendix D would only be capable of detecting areas of active corrosion in a tank floor. The monitoring systems would not be

sensitive to areas of in-active corrosion that existed before the installation of the monitoring system. For this reason, it is highly recommended that a baseline assessment of the condition of the tank floor be completed at the time of installation of an SHM system. This will produce a known baseline or reference state to which future states may be compared.

It should be noted that the existing monitoring technologies for tanks may only be applicable for certain tank geometries/configurations and, in most cases, are intended for applications on aboveground storage tanks. The monitoring system sensors may need to be installed in specific locations and, in some cases, the sensor array may need to be designed specifically for the tank-of-interest.

As an example, for several of the identified SHM systems, access to the tank chime area is typically required for sensor installation. The chime area is the small portion of the tank floor that extends beyond the tank walls and is typically several inches wide. If the chime area is not wide enough (typically < 1 to 2 inches) to install the monitoring sensors, or if access to the chime area is not possible (e.g., it is below grade), it may not be possible to utilize several of the identified SHM technologies, as is. In these cases, excavation and/or tank modification may be considered to deploy the technology. Furthermore, the design and number of required sensors will be a function of tank diameter in most cases, with larger tanks requiring more sensors. For more specific information on the applicability and design requirements of SHM systems for a specific storage tank, it is recommended that the reader contact the OEMs and/or service providers of these technologies.

5.4 Potential Future R&D to Improve Tank Inspection Technologies

Based on the technology review that was completed for the preparation of the summary table in Appendix D, several technology gaps or areas for improvement were identified that could benefit from future research and development efforts. As NDE and SHM technology is constantly evolving, tank owners are encouraged to contact EPRI for guidance in the event that they find their tank inspection needs fall into a technology gap.

5.4.1 NDE for Crack Sizing in Tank Welds

A majority of storage tanks in the oil and gas industry are constructed from carbon steel and corrosion is the principal concern, though cracking is also possible. In addition to carbon steel, the nuclear industry has a proportionally large number of storage tanks that are constructed from stainless steel or aluminum. These tanks typically have different degradation concerns than carbon steel tanks, such as crack formation in welds.

Crack length and depth sizing has been a focus of several NDE methods for many years with many UT and electromagnetic technologies available for this application. Several examples include:

1. Time-of-Flight Diffraction (TOFD) UT
2. Phased-Array UT (PAUT)
3. Alternating Current Field Measurement (ACFM)
4. Other advanced Eddy Current based methods

These techniques have been primarily developed for application by hand or by automated X-Y scanning fixtures. Based on the technology review completed for this report, the current robotic devices for tank inspection are not equipped with NDE technologies capable of length and depth sizing of cracks. It is therefore recommended that an area for potential future research and development is the integration of existing crack-sizing NDE technologies with existing or new robotic delivery platforms.

5.4.2 Large-Area Inspection/Screening

Inspection speed can be a critical factor when a tank must be taken out of service for an inspection. Furthermore, nearly all of the existing NDE technologies for tank inspection, manually or robotically applied, provide localized measurements that require the sensors to be scanned over the entire surface to be examined. Sensor arrays with large effective footprints or technologies that have the capability to inspect areas outside of the sensor footprint have the potential to speed up inspections significantly.

Based on this observation, another area for potential future research/development is the investigation into new or existing sensor array technologies that have larger effective footprints than the sensors currently in use. This could include ultrasonic arrays, as well as eddy current arrays, or other electromagnetic sensor arrays. Alternatively, large-area screening methods, such as guided wave testing, could be investigated as a means to screen large areas quickly to identify questionable areas for focused NDE.

5.4.3 Direct Assessment through Tank Liners

Several electromagnetic NDE technologies for tanks, such as MFL and Saturated Low-Frequency Eddy Current testing, are able to inspect for volumetric wall loss through protective liners; however, it is not clear whether or not the accuracy of these methods would meet the nuclear industry's requirements to be considered Direct Assessment techniques. A potential area for future research/development would be the completion of a round-robin investigation into the sizing capabilities of any applicable NDE technologies for inspection through protective liners. Such a study has the potential to facilitate the statistical characterization of the performance of these technologies in an independent manner.

5.4.4 Structural Health Monitoring of USTs

Several guided wave and acoustic emission solutions for the long-term monitoring of aboveground storage tanks have been identified in the technology table provided in Appendix D. These technologies are able to monitor portions of the tank for active corrosion. For ASTs, these techniques utilize sensors that are mounted on the accessible areas outside of the storage tank. For USTs, access to the tank exterior is typically not possible and the existing monitoring solutions do not apply. Furthermore, even with access, UST configurations can be substantially different than ASTs and the existing monitoring solutions may not be directly applicable without modification.

For these reasons, there are several opportunities for future research/development for the long-term monitoring of USTs. Some specific areas include:

- Modified sensor array designs for UST tank configurations;
- Modified data processing routines for UST tank geometries; and
- Intrinsically safe in-tank mounted sensors.

Overall, the long-term monitoring solutions for storage tanks are the newest category of NDE/SHM technology and there are undoubtedly many more areas for improvement, new applications, and new technology.

6
STATISTICAL METHODS FOR INSPECTION REDUCTION

A typical NPP storage tank might be 45 ft. in height and 20 ft. in diameter (see Appendix A, Sections A.2.5.3 and A.2.5.4). Inspection of the complete surfaces of this typical tank would require examination of thousands of square feet of surface, down to the resolution required to detect all significant flaws. This is impractical, costly, and time consuming. Strategies based on statistics could potentially provide opportunity to justify the inspection of only a portion of the tank, the results of which can then be used to make inferences about the state of the whole tank.

Two scenarios are addressed below.

6.1 Scenario 1: "Failed" or "Not Failed"

6.1.1 Pre-Defined Failure Criterion

Within nuclear power operations and inspections, failure criteria is often established as a part of the licensing for the plant. This would be consistent with establishing a "pre-defined failure criterion" which may be used for statistical processes. For instance, prior to beginning an inspection, a Failure Criterion is chosen. This criterion, for example, may be "Remaining Wall Less Than 50% of Nominal Wall." A tank with a large surface area can be divided into many segments, for example, 10,000 segments of one sq. ft. each. For an example let it be given that 100 of these segments are inspected, with two (2) failing, based on the chosen failure criterion, and the remaining 98 not failing. Based on this sample of 100, what inference can be drawn about the whole tank with 10,000 segments? The answer to this can be found from the use of the Binomial Distribution. As described below in Section 6.1.3, one can state with 95% confidence that the proportion of failed segments in the whole tank will be ≤ 0.062 (6.2%).

6.1.2 Failure Criterion Chosen Post-Inspection

In this scenario, the results of the inspection are more quantitative. For the inspected segments, the measured minimum wall thickness in each segment is recorded. The results are then organized into a frequency table, as seen in Table 6-1.

Table 6-1
Sample Wall Thickness Data

Minimum Thickness in a Segment, t (in.)*	No. of Segments	Cumulative No. of Segments with Thickness ≤t
0 - 0.05	0	0
0.05 - 0.1	0	0
0.1 - 0.2	2	2
0.2 - 0.3	1	3
0.3 - 0.4	2	5
0.4 - 0.5	95	100

* Upper bound of each range is inclusive; lower bound is exclusive, except for 0, which is inclusive.

Under this scenario, the failure criterion can be defined after the inspection has been completed. For example, it may be defined that any segment having thickness ≤ 0.1" as failed. In the above table, that number is zero (0). Per the discussion in Section 6.1.3, based on the sample size of 100, one can say that there is a 95% confidence level that the proportion of "Failed" segments in the whole tank is ≤0.03.

6.1.3 Binomial Distribution: Sample Size and Confidence Interval

The best single estimate of the true proportion of items having a given characteristic (e.g., failures, corroded, unacceptable, etc.) in some well-defined population is given by

$$p = \frac{r}{n}$$

Where:

p = estimate of the true proportion

r = number of items with the specified characteristic

n = sample size (number of items inspected)

The basis of the above estimate is the Binomial distribution. The following assumptions are required for it to be valid [7].

1. The number of observations, n, is fixed.
2. Each observation is independent.
3. Each observation represents one of two outcomes ("success" or "failure").
4. The probability of "failure", p, is the same for each outcome.

The limitation of the above estimate is that it will vary if another sample of size, n, is taken. Rather than indicate the best single estimate of true proportion, an interval estimate may be preferred to account for the sampling error. Depending on the nature of the problem, a one- or two-sided interval with a desired confidence level can be constructed.

In the case of failures, a one-sided confidence interval may be appropriate. It will allow you to make a statement such as, "given detection of one failure in a sample of size 50, one can state with 95% confidence that the actual proportion of failures in the population will be less than 0.091 or less than 0.126 with 99% confidence."

Table 6-2, below, shows a sample of confidence interval limits for the proportion, extracted from a table of One-Sided Confidence Intervals at 90%, 95%, and 99% Confidence, in a handbook about experimental statistics [8].

Table 6-2
Sample of Binomial Distribution Confidence Intervals

r	0.90	0.95	0.99	0.90	0.95	0.99	0.90	0.95	0.99
	n = 29			n = 50			n = 100		
0	0.076	0.098	0.147	0.045	0.058	0.088	0.023	0.030	0.045
1	0.128	0.153	0.208	0.076	0.091	0.126	0.038	0.047	0.065
2	0.173	0.202	0.260	0.103	0.121	0.158	0.052	0.062	0.082
3	0.216	0.246	0.307	0.129	0.148	0.187	0.066	0.076	0.097
4	0.257	0.288	0.351	0.154	0.174	0.215	0.078	0.089	0.112
5	0.297	0.329	0.392	0.178	0.199	0.242	0.091	0.102	0.126
6	0.335	0.368	0.432	0.201	0.223	0.267	0.103	0.115	0.140
7	0.373	0.406	0.470	0.224	0.247	0.292	0.115	0.128	0.153
8	0.409	0.443	0.507	0.247	0.270	0.316	0.127	0.140	0.166
9	0.445	0.479	0.542	0.269	0.293	0.340	0.138	0.152	0.179
10	0.481	0.514	0.577	0.291	0.316	0.363	0.150	0.164	0.191

6.2 Scenario 2: Fitting Inspection Results to a Distribution

Another option to be explored is to fit the cumulative distribution of minimum thickness to an Extreme Value distribution. Once the distribution is fitted, the confidence intervals can be calculated. The advantage of using this approach is that it allows one to extrapolate beyond the measured values of minimum thickness. For example, one could specify the level of confidence that a remaining wall of less than 10% of nominal wall exists. The shortcoming of this technique is that it requires justification for the use of the distribution (discussed further in Section 6.3, Suggestions for Further Research).

Taking the minimum thickness of each segment creates an extreme (minimum) value problem. The distribution of minimum thickness per sheet can be approximated by a Weibull (Extreme Value Type III) distribution. The sampled minimum thicknesses per segment can be fitted to a Weibull cumulative probability distribution of the following form [8].

$$\begin{cases} 1 - e^{-(x/\lambda)^k} & x \geq 0 \\ 0 & x < 0 \end{cases}$$

Where:

e is the base of the natural logarithm.

x is the independent variable, in this case the minimum thickness.

λ is the scale parameter of the distribution, with $\lambda \in (0, +\infty)$.

k is the shape parameter of the distribution, with $k \in (0, +\infty)$.

The confidence bounds can also be computed. The fitted distribution can then be extended to thicknesses not observed in the sample.

Since the method for calculating the minimum already includes measuring the other *n* locations in the segment, there is a high reward to effort for using all *n* data points per segment. Doing so will allow for calculations to investigate aspects such as how thickness is distributed within segments, ranges of thickness within segments, maximum thicknesses, etc. These within-segment statistics can be used to make implications about multiple segments or the population as a whole such as average thickness, variance in thickness, maximum thickness, amount of thickness above/below a certain measurement, etc.

6.3 Suggestion for Further Research

Scenario 1 is simple and straightforward to implement, relying only on the Binomial Distribution, the use of which requires only that four (4) assumptions be met, as described in Section 6.1.3. These assumptions are easily met for a typical tank inspection. However, information provided by the extrapolation of the sample inspection results to the whole tank may be of limited usefulness. Knowing how many unit areas of the tank surface will fail to meet a specified t_{min} value, while beneficial, is not the ultimate goal of the inspection (unless, perhaps, it can be determined that the number is zero). Alternatively, an accurate estimate of the thickness of the thinnest spot on the tank, for comparison to a specified t_{min}, is preferred. The method described in Scenario 2, the Extreme Value approach, can potentially provide that information.

Recall the details of the inspection process, as described previously. There is a tank with a certain surface area, the condition of which needs to be determined. First, that surface area is divided into unit areas of some standard size (e.g., six square inches). Next, a number of those unit areas, at randomly chosen locations, are inspected to determine the minimum remaining wall thickness of each. From this dataset of minimum wall thicknesses the condition of the complete surface area can be extrapolated statistically. More specifically, it can be determined, with a certain level of confidence, the thickness of the thinnest location of the tank. The Extreme Value approach provides a method for doing this, but before it can be applied properly the sample inspection results must satisfactorily meet the requirements to use the approach.

Future research on this approach should focus on determining if the distribution of sample inspection results approximates a Weibull distribution, and the unit area size and number of unit areas resulting in the best fit. This research might be carried out using existing inspection data, but additional field work might be required to obtain the necessary dataset.

7
REFERENCES

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A
TANK DATA ANALYSIS

An EPRI member survey was conducted in January 2014 to gain information on storage tank inspections at nuclear power plants. The survey included questions related to tank geometry, inspection history and information, categorizing flaw characteristics, and identifying maintenance practice such as coatings and cathodic protection. This section discusses the analysis of the survey results to identify trends.

In total 49 survey responses were submitted by the EPRI members. Section A.1 provides details of the analyses completed on the survey results. To add to these survey results, Underground Piping and Tank Integrity (UPTI) databases were gathered from multiple utilities to provide additional information on tank configuration and inspection methods. Sections A.2 through A.5 provide details of the analyses conducted on the combined dataset. For the analyses of the survey and combined data in Appendix A, percentages are rounded to the nearest integer. The combined dataset yielded a total of 143 tanks, from 43 plants.

A.1 Summary of Survey Responses

This section reviews the responses provided by the members in the surveys. In this section, the following definitions are used in describing the responses:

- **Complete Response:** The member provided answers for every section on the survey.
- **Partial Response:** The member provided answers for just a few sections on the survey.
- **Incomplete Response:** The member provided answers for only the first section on the survey.
- **No Response:** No Response was provided for a survey question.
- **Unknown:** Either the value ‘Unknown’ was provided for a survey response, or it was unclear what the intent of the survey answer was for the given question.

The following plot shows the breakdown of the surveys submitted by the members.

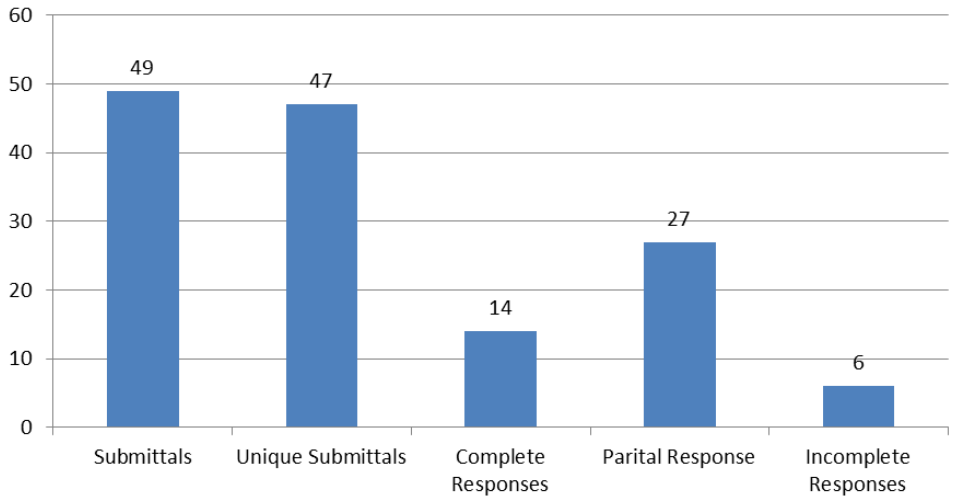

Figure A-1
Summary Stats for Tank Inspection Surveys

A total of 120 survey invites were sent to the utility members in two rounds. A total of 49 surveys were submitted by the members. Of those, two (2) duplicate entries were received. From the remaining 47 unique surveys 30% provided complete responses, 57% provided partial responses, and the remaining only completed the first section of the survey. To provide meaningful analysis of the survey dataset, the remainder of this section only considers the survey responses that were complete, or partially complete (41 responses).

The following plot shows the breakdown of complete and partially complete survey responses by country.

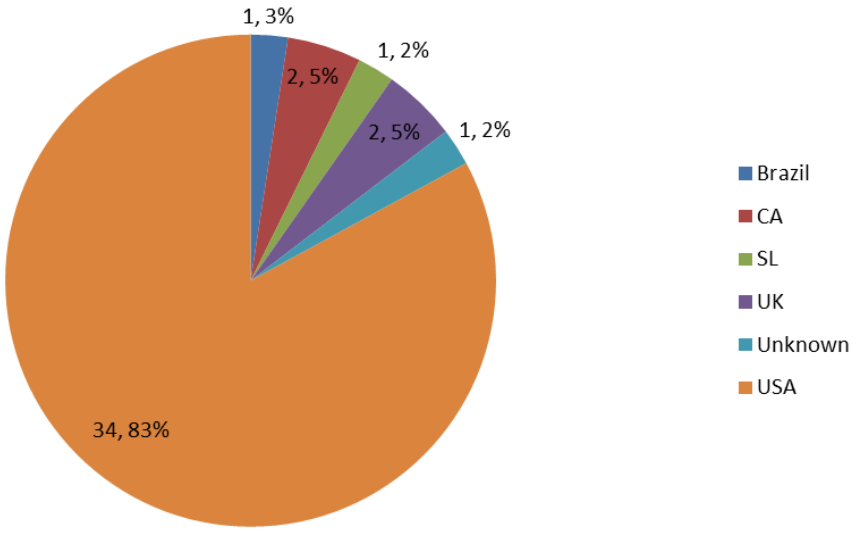

Figure A-2
Summary of Survey Responses, by Country

Approximately 83% of the survey responses were from plants located in the United States. The remaining responses were from plants located in Brazil, Canada, Slovenia, and the United Kingdom.

A.1.1 Systems

The following plot shows the breakdown of tanks by system from the survey responses.

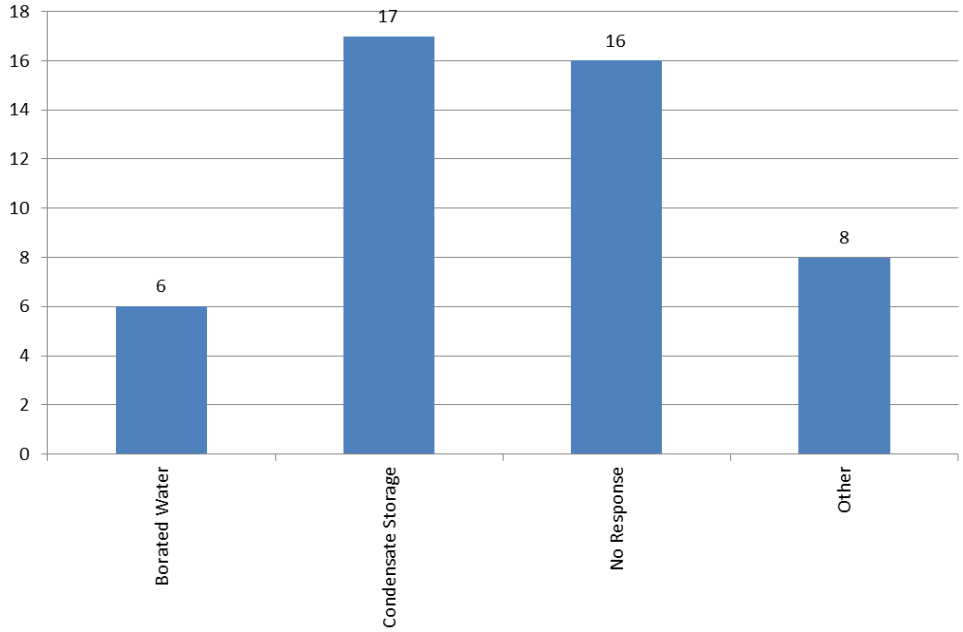

Figure A-3
Summary of Survey Responses, by System

The majority of the tanks covered by the survey were used in Condensate Storage Systems (41%). Sixteen (16) surveys (40%) provided no response for the Tank System name.

A.1.2 Design Standard

The following plot shows the standards used to design the Tanks represented by the survey responses. Approximately 64% of the survey responses indicated ASME as the design standard for the tank.

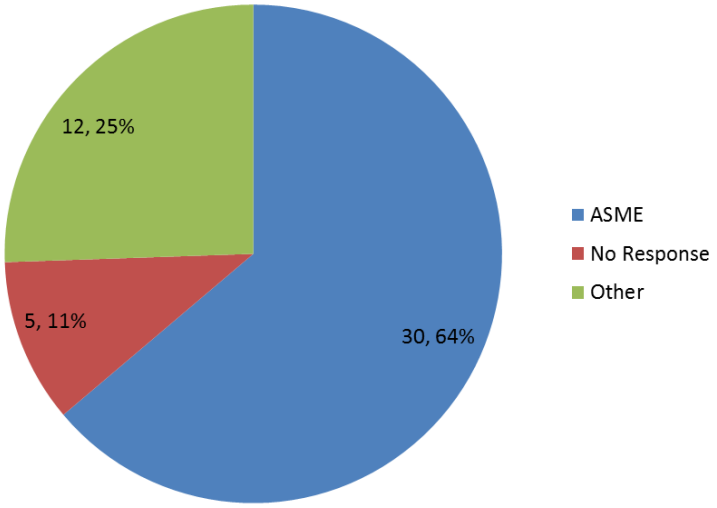

Figure A-4
Summary of Survey Responses, by Design Standard

Of the 25% that were listed as other, they represented a combination of the following:

- Sargent Lundy Design Specification
- ANSI B31.7
- API
- AWWA
- GE Specs
- No Response/Unknown, and Various

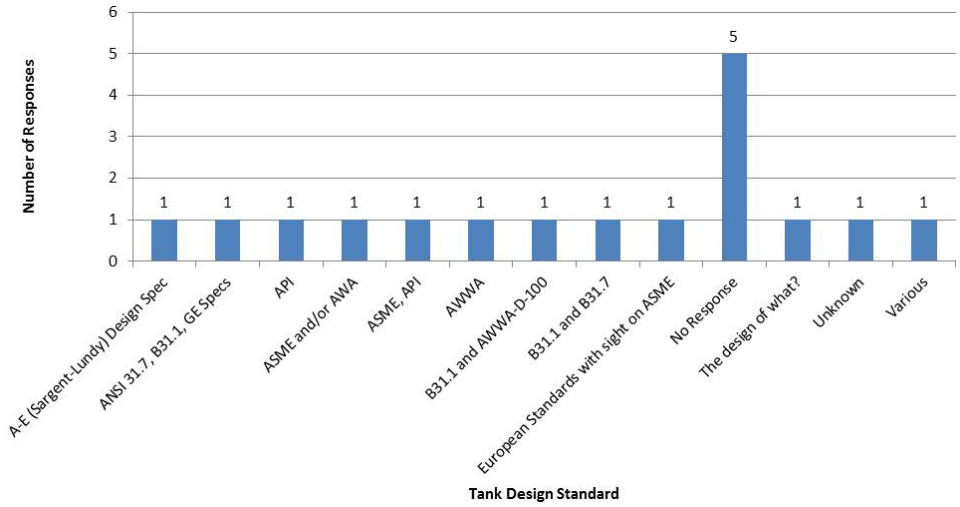

Figure A-5
Other Design Standard - Survey Responses

A.1.3 Management Programs

The following plots show the scope of the tanks relative to the Ground Water Protection Initiative (GWPI) and the Underground Piping and Tank Integrity (UPTI) programs.

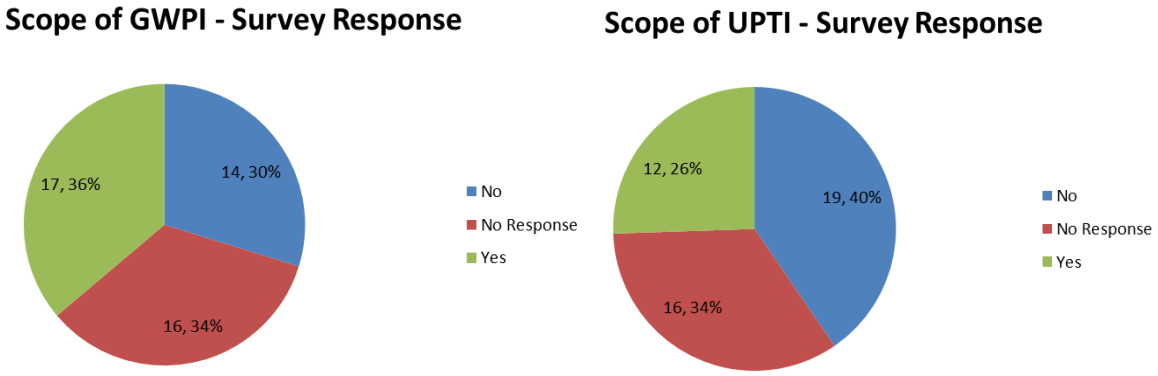

Figure A-6
Summary of Survey Responses, by Program

Twenty-six percent of the tanks described in the survey responses are within the scope of the UPTI program for the plant. Thirty-six percent of the tanks described in the survey responses are within the scope of the plant's GWPI program.

Thirty-four percent of the survey responses were not associated with either the GWPI or UPTI programs.

A.1.4 Statistical Significance of Survey Response Data

As discussed in the previous section, only 40-50% of the 41 survey responses provided complete, useable, data for each survey question. The other 50-60% of data provided was not complete or no meaningful responses were given. In an attempt to provide a review with statistical significance, additional UPTI database tank data were added to the survey responses for additional analyses in the following sections.

A.2 Combined Tank Data

In an attempt to improve the significance of the tank data, approval was obtained from fifteen plants to use existing data from UPTI databases. The UPTI data were combined with the complete/partially complete survey responses and duplicates were removed for further analysis. For select cases, the data could be used to answer the survey questions, but was not a direct match to the survey question. In those cases, the logic or interpretation used to provide answers to the survey question is discussed in the following sections. The remaining sections present the findings of the analyses of the combined data, and are organized by the order they were presented in the survey. When survey responses were incomplete, the missing data were treated as No Response or Unknown, and may indicate areas for additional research.

A total of 43 plants with 143 tanks are represented in the combined dataset used in the analysis for this report. The following plot shows the breakdown of the tanks represented by country. Ninety-five percent of the tanks are located in the United States.

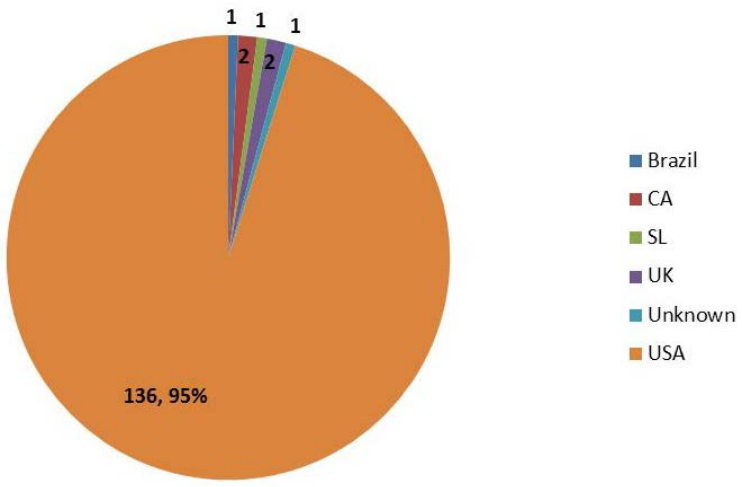

Figure A-7
Summary of Combined Responses, by Country

The following sub-sections evaluate various attributes of the combined dataset. During this analysis, and throughout the remainder of this Appendix, the following definitions are used to describe responses:

- NR: No Response was provided for a survey question.
- Unknown: Either the value 'Unknown' was provided for a survey response, or it was unclear what the intent of the survey answer was for the given question.

A.2.1 Systems

The plot below shows the distribution of the tanks by their various systems. The Fuel Oil system had the greatest population of tanks, 47 out of the 143 tanks (33%). Condensate Storage was the next largest, with 24 out of the 143 tanks (17%) analyzed. For the combined dataset, there were only 11 tanks (8%) that did not have an associated system name.

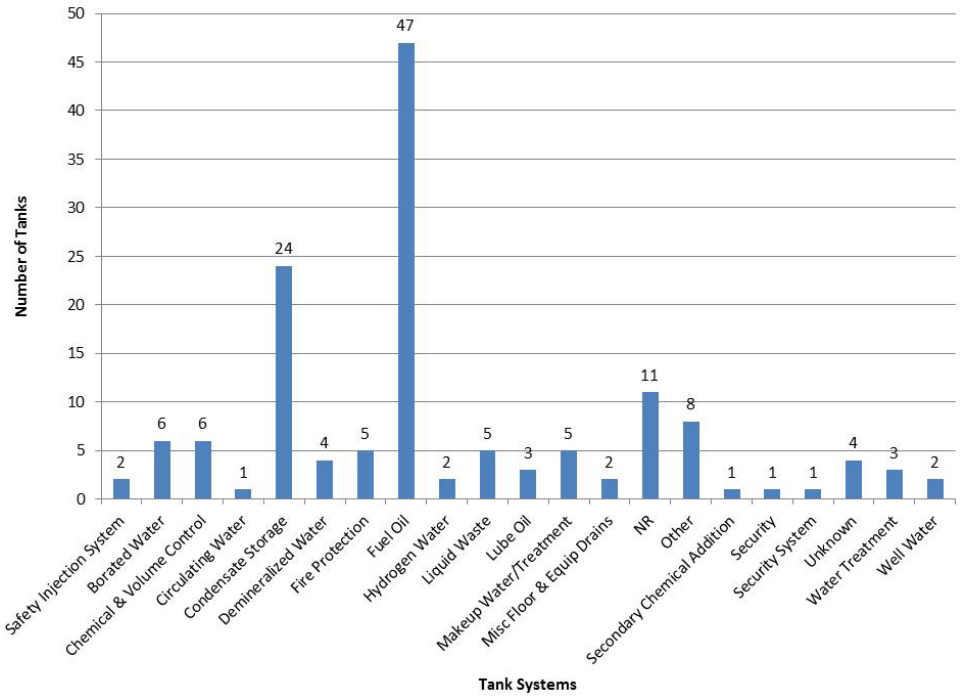

Figure A-8
Summary of Combined Responses, by System

A.2.2 Safety Significance

The following plot shows the distribution of tank safety significance (i.e., safety related). Fifty percent of the tanks are not safety related, while 26 tanks (18%) did not provide safety-significance information.

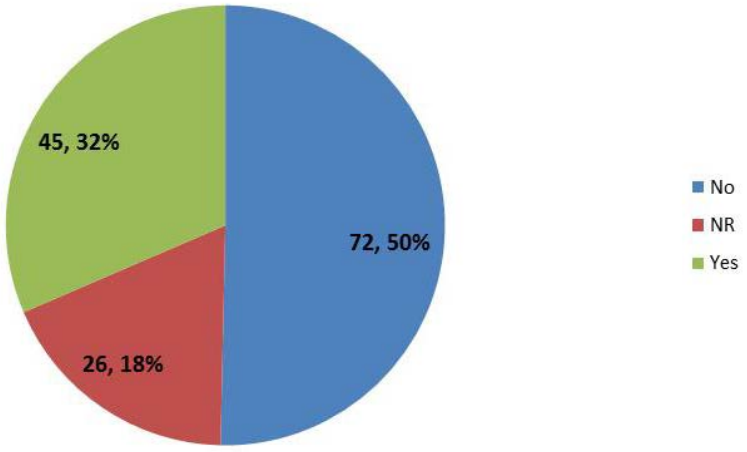

Figure A-9
Summary of Combined Responses, by Safety Significance

A.2.3 Design Standard

The plot below shows the design standards used for tanks included in this analysis. Fifty-nine tanks (41%) used ASME design specification, 12 tanks (8%) used the API 650 specification, and 50 tanks (35%) did not provide a designated design specification.

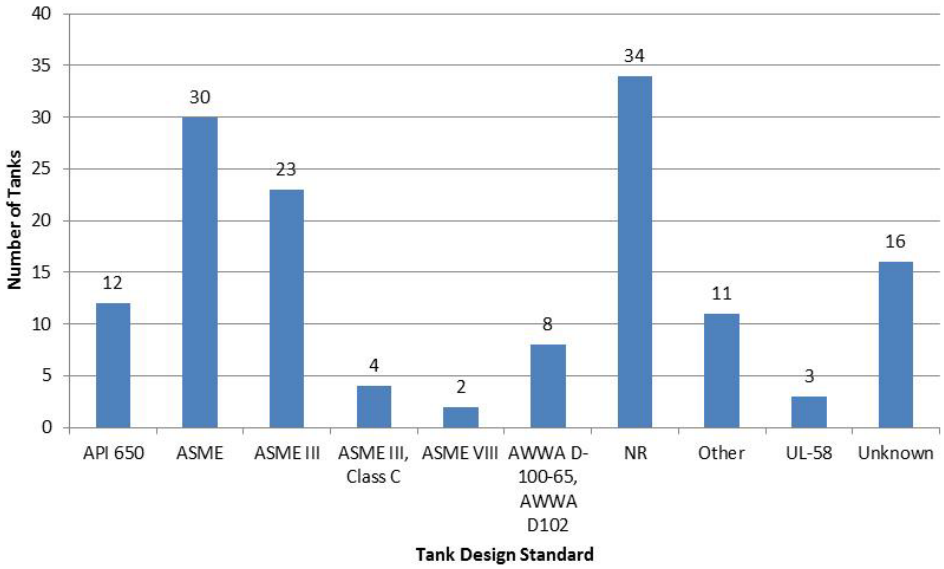

Figure A-10
Summary of Combined Responses, by Design Standard

A.2.4 Management Programs

The following plots show the scope of the tanks relative to the Ground Water Protection Initiative (GWPI) and the Underground Piping and Tank Integrity (UPTI) programs.

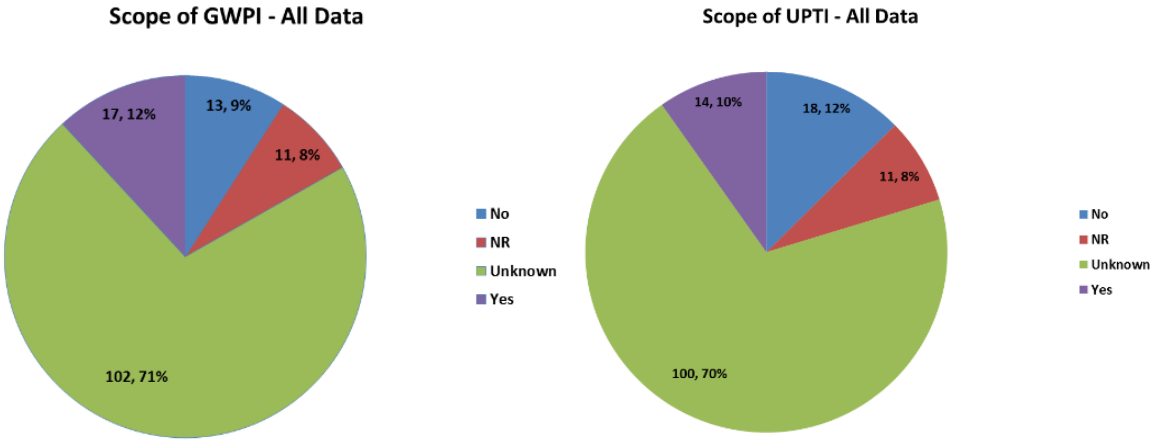

Figure A-11
Summary of Combined Responses, by Management Program

For both programs, 70% of the answers are unknown. This large percentage is associated with the use of UPTI database information. The UPTI databases do not contain a specific field which indicates if the tank is within the scope of either program.

A.2.5 Construction

The following sections discuss the distribution of the type of construction characteristics for the tanks.

A.2.5.1 Seam Type

Twenty-seven tanks are welded (19%), eleven (11) tanks (8%) did not provide data for this question, 102 of the tanks are shown as Unknown (71%), and one tank is constructed of reinforced concrete. The large percentage of unknown data is associated with the use of UPTI database information. The UPTI database does not contain a specific field which indicates tank construction method.

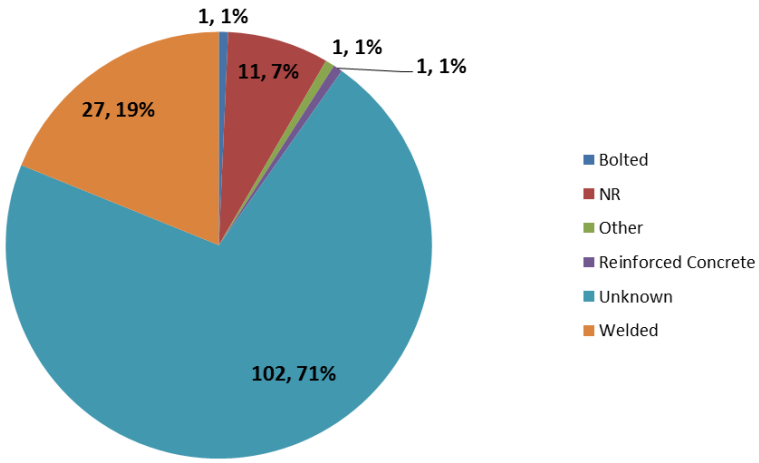

Figure A-12
Summary of Combined Responses, by Construction

A.2.5.2 Manufacturer

The following plot shows the different manufacturers for the survey and tank database responses. Seventy-three tanks (51%) provided no data for the tank manufacturer or were listed as unknown.

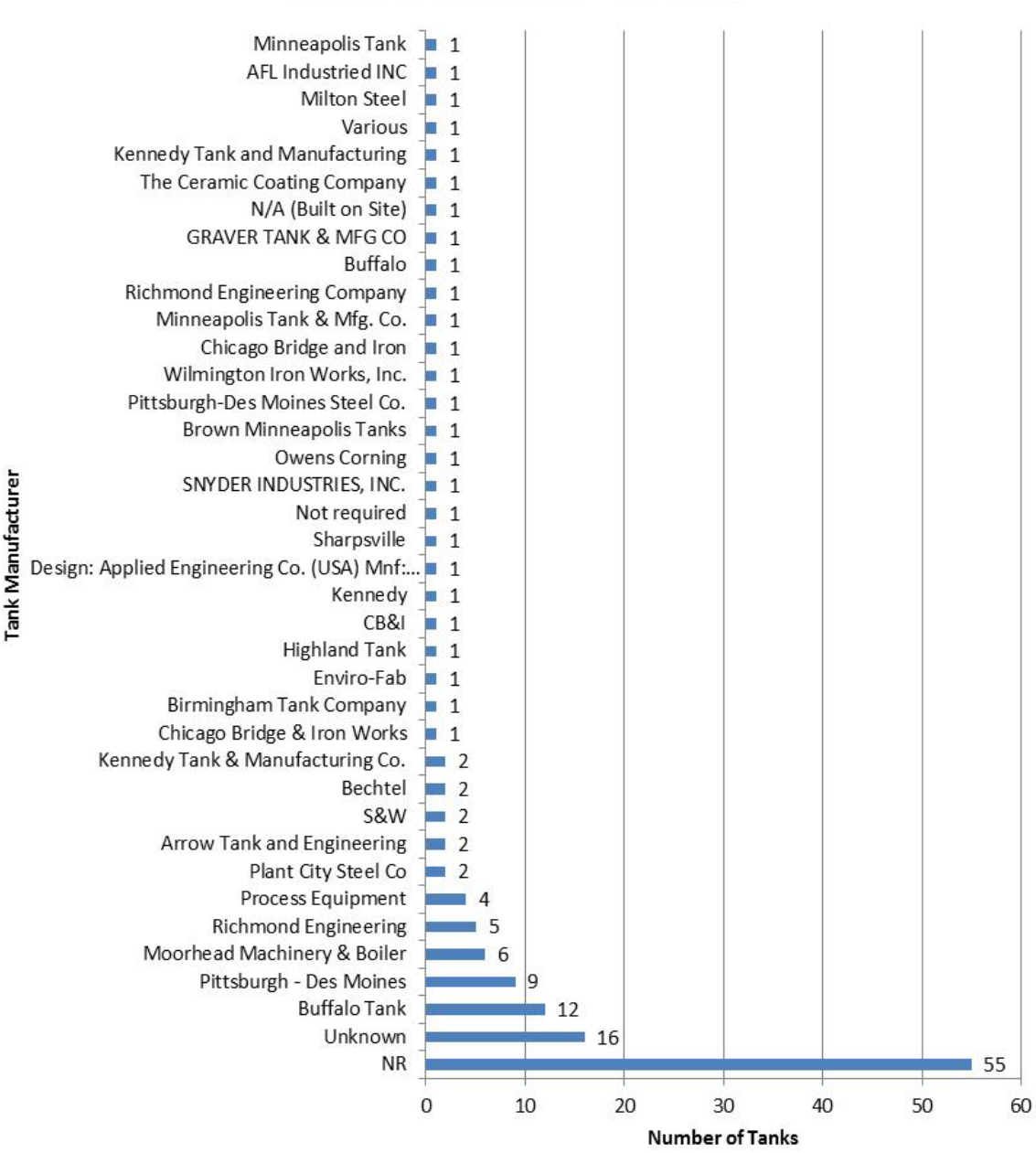

Figure A-13
Summary of Combined Responses, by Manufacturer

A.2.5.3 Height

The following plot shows the distribution of the tank height. Forty-six tanks (32%) had no height data provided, 19 tanks (13%) are from 30-40 feet high, and three (3) tanks (2%) are over 50 feet high.

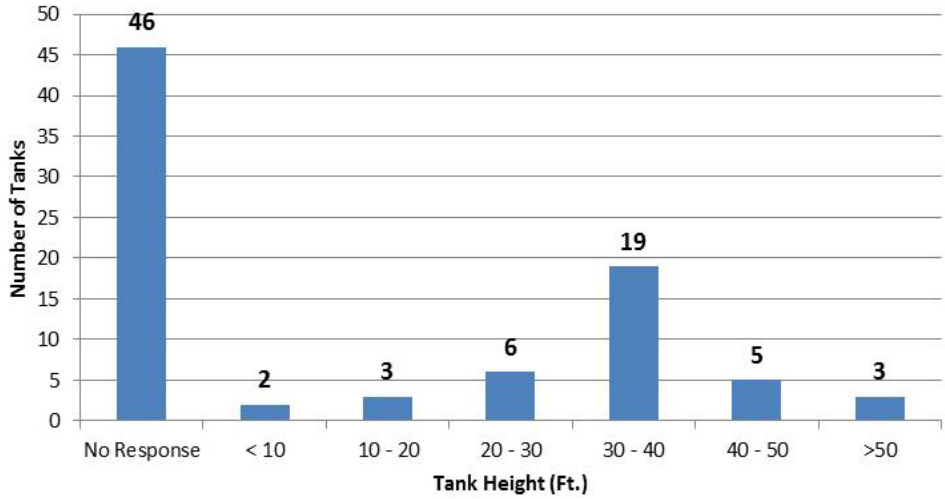

Figure A-14
Summary of Combined Responses, by Height

A.2.5.4 Diameter

The following plot shows the distribution of the tank diameters. No diameter data were reported for 39 tanks (27%), 48 tanks (34%) have a diameter between 10-20 feet, 19 tanks (13%) have a diameter between 40-50 feet, and two (2) tanks have a diameter greater than 50 feet.

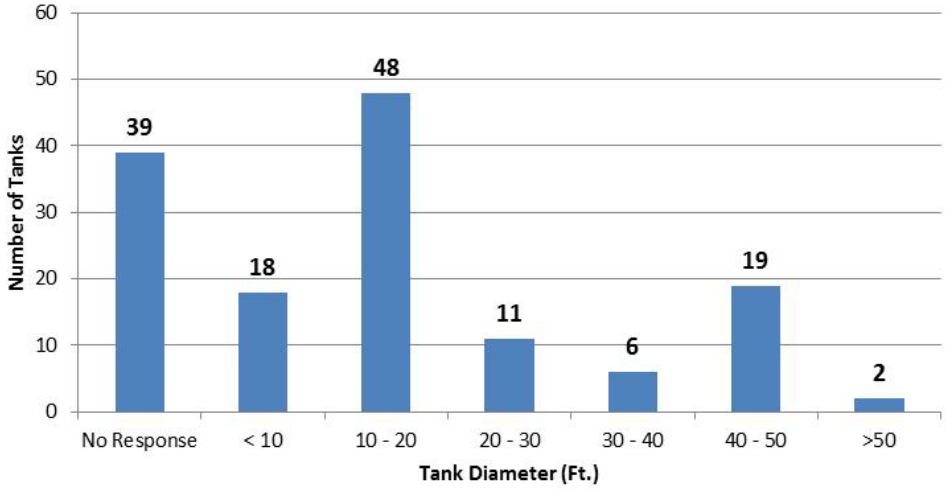

Figure A-15
Summary of Combined Responses, by Diameter

A.2.5.5 Capacity

The following plot shows the distribution of tank capacity. Thirty tanks (21%) had no data reported for the capacity, 31 tanks (22%) have a capacity of 50,000-100,000 gallons, 21 tanks (15%) have a capacity of 250,000-500,000 gallons, and seven (7) tanks (5%) have a capacity of greater than 500,000 gallons.

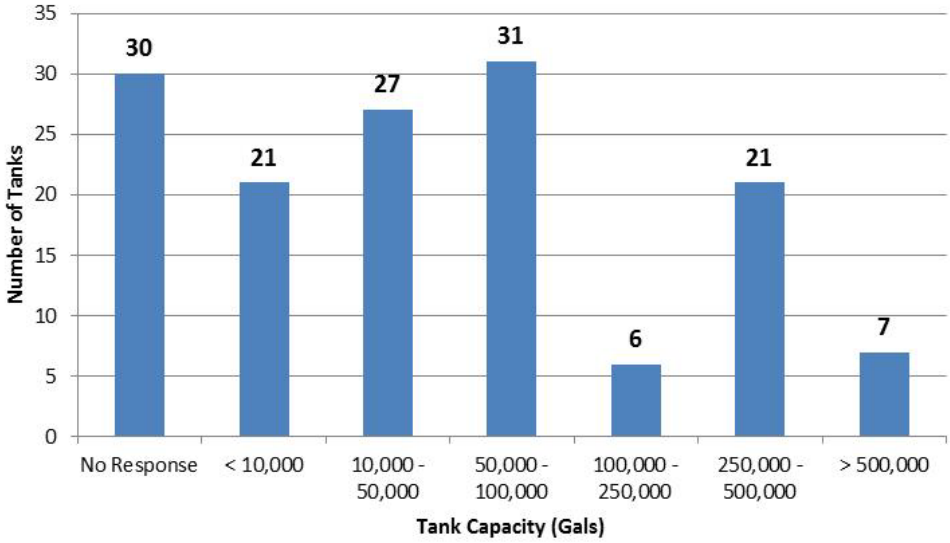

Figure A-16
Summary of Combined Responses, by Capacity

A.2.5.6 Depth of Fluid

The following plot shows the distribution of fluid depth in the tanks. While the survey asked for values in feet, the responses were converted to depth in percent for comparison between tanks. One-hundred twenty-eight tanks (90%) have an unknown fluid depth. The large percentage of unknown data is associated with the use of UPTI database information. The UPTI database does not contain a specific field for fluid depth.

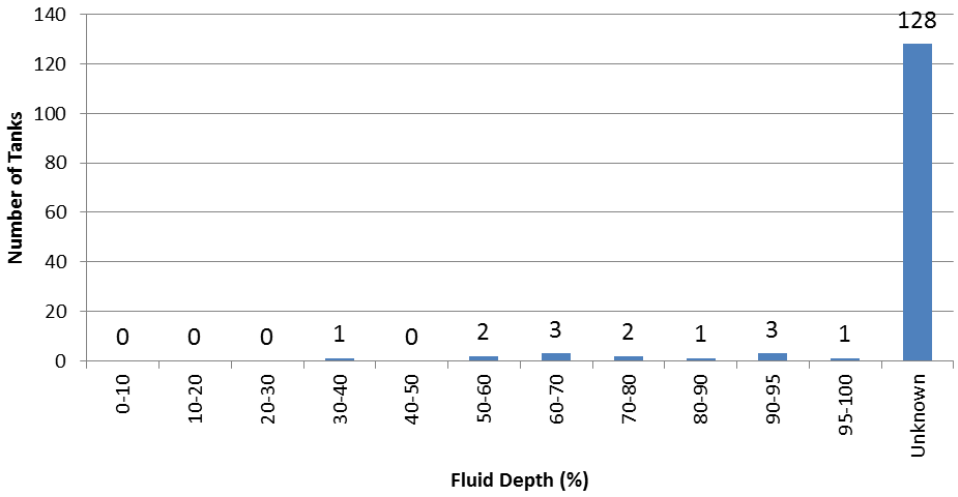

Figure A-17
Summary of Combined Responses, by Fluid Depth

A.2.5.7 Support/Foundation

The following plot shows the distribution of the tank support/foundation. Forty-seven (47) of the tanks (33%) have concrete or reinforced concrete foundations. Thirty-three (33) tanks from the UPTI databases had "Not applicable" listed for the tank pad. All 33 tanks are buried, and it is unclear what is supporting the tank. Five (5) tanks from the UPTI database had "Other/Unknown" listed for the tank pad. All of these tanks are aboveground. Support/foundation information was not provided for 27 of the tanks (19%).

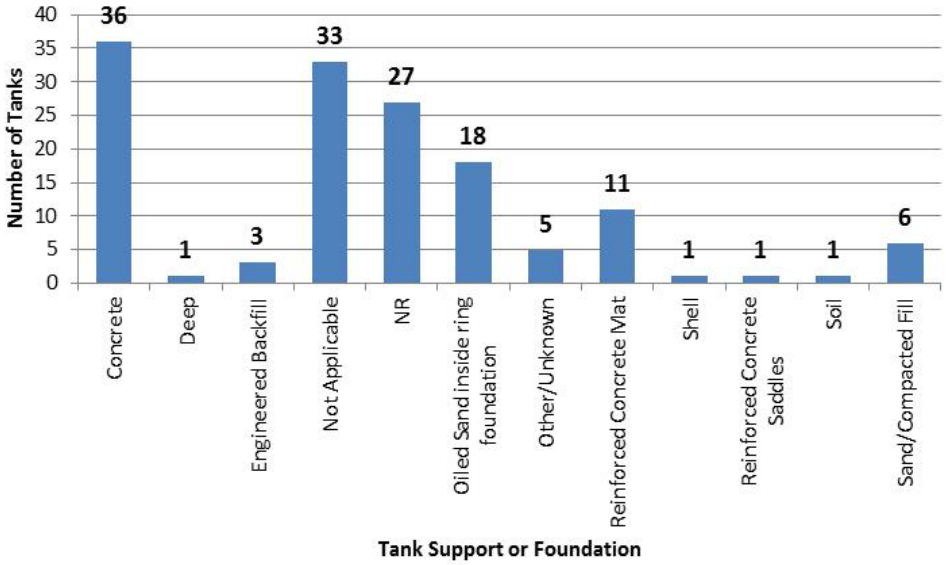

Figure A-18
Summary of Combined Responses, by Support/Foundation

A.2.5.8 Double Wall/Bottom

The following plots show the distribution of tanks with double wall and bottoms. Thirteen (13) tanks (9%) were listed as having a double wall, eight (8) tanks (6%) were listed as having a double bottom, and 23 tanks (16%) provided no data for either parameter.

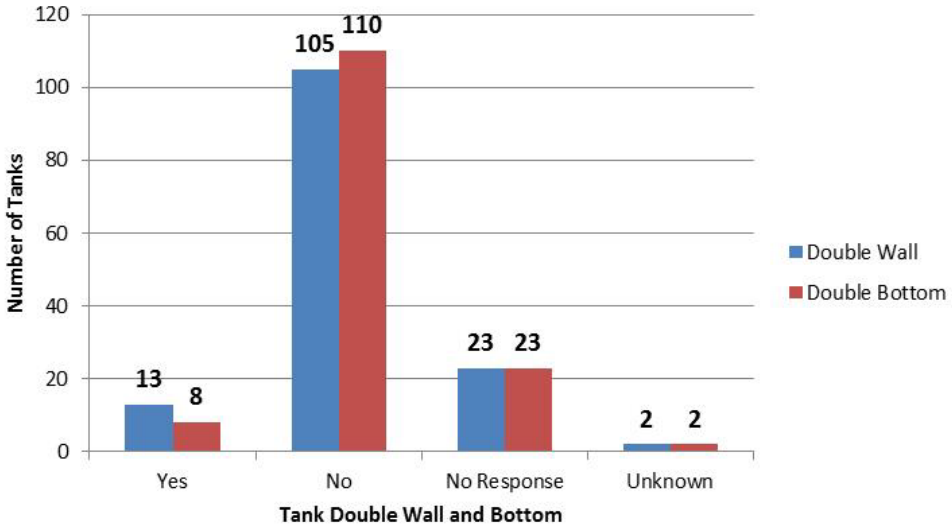

Figure A-19
Summary of Combined Responses, by Double Wall/Bottom

A.2.5.9 Wall Thickness

The following plot shows the distributions of wall thickness. The tanks with a thickness of twelve (12) and 21 inches are reinforced concrete tanks for Condensate Storage. It is unknown if the tanks with a thickness of 99 inches are reliable. Fifty three (53) tanks (37%) did not provide data for this parameter.

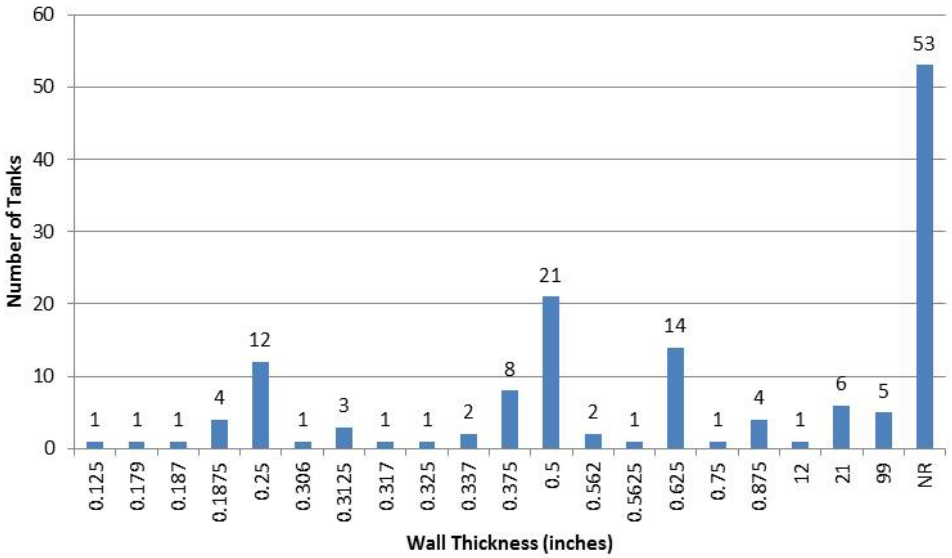

Figure A-20
Summary of Combined Responses, by Wall Thickness

A.3 Review of Failure Mechanisms

While the survey asked over 60 questions, only a portion of these questions address parameters that can contribute to degradation, and thus be considered failure mechanisms. This section analyzes the majority of the tank data covered by the survey and focuses on the parameters which may affect flaws found on/in the tanks. The following parameters were chosen because of industry experience and knowledge of tank risk models.

1. **Materials:** This parameter pertains to the type of material used to construct the tank. Different materials will have different degradation characteristics based on the content and environment, and can lead to failure.
2. **Content:** This parameter pertains to the fluid content in the tank. Contents will have varying corrosive effects depending on the tank material, pH of the fluid, and amount of oxygen available for bacterial growth.
3. **Coatings:** This parameter pertains to the coatings used, both internal and external, to protect the tank material. Internal coatings (linings) can reduce the corrosive or bacterial growth effects of the tank fluid. External coatings can reduce the corrosive effects of moisture and soil contact.
4. **Environment:** This parameter pertains to whether the tank is located above or below grade. Aboveground tanks can experience degradation due to third-party damage and corrosion due to moisture in the air. Buried tanks can experience degradation due to being in contact with the soil.
5. **Age:** This parameter pertains to the age of the tank. The older the tank the longer it has been exposed to corrosive contents, soil, and moisture in the air; and, thus the tank is more prone to degradation.
6. **Operating Conditions:** This parameter pertains to the operating pressure and temperature of the tank. Elevated operating pressure leads to increase stress in tank components while elevated temperatures can result in coating/lining degradation and support the growth of bacteria.
7. **Orientation:** This parameter pertains to the tank orientation, either horizontal or vertical. Horizontal tanks may have more surface area in contact with corrosive fluids and/or soils which increases the greater potential for degradation.
8. **CP Coverage:** This parameter pertains to whether the tank is internally or externally cathodically protected. Cathodic Protection is utilized to mitigate the threat of corrosion through the formation of polarization. A properly designed and operating CP system should provide better protection to degradation than tanks with no CP System.

A.3.1 Materials

The following plot shows the distribution of materials used for the tanks. Eighty-two tanks (57%) are constructed with carbon steel or double-wall carbon steel, 16 tanks (11%) are made of stainless steel, and 30 tanks (21%) provided no data for the tank material.

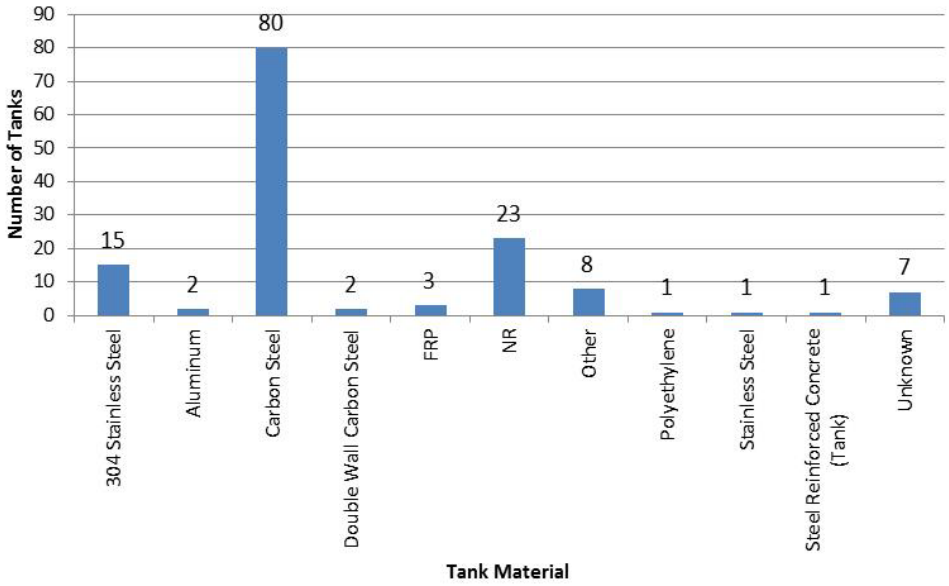

Figure A-21
Summary of Combined Responses, by Material

A.3.2 Content

The following plot shows the distribution of tank content. Fifty-two tanks (36%) contained some form of fuel oil, 13 tanks (9%) contain condensate/demineralized water, and 28 tanks (20%) provided no response for the tank content.

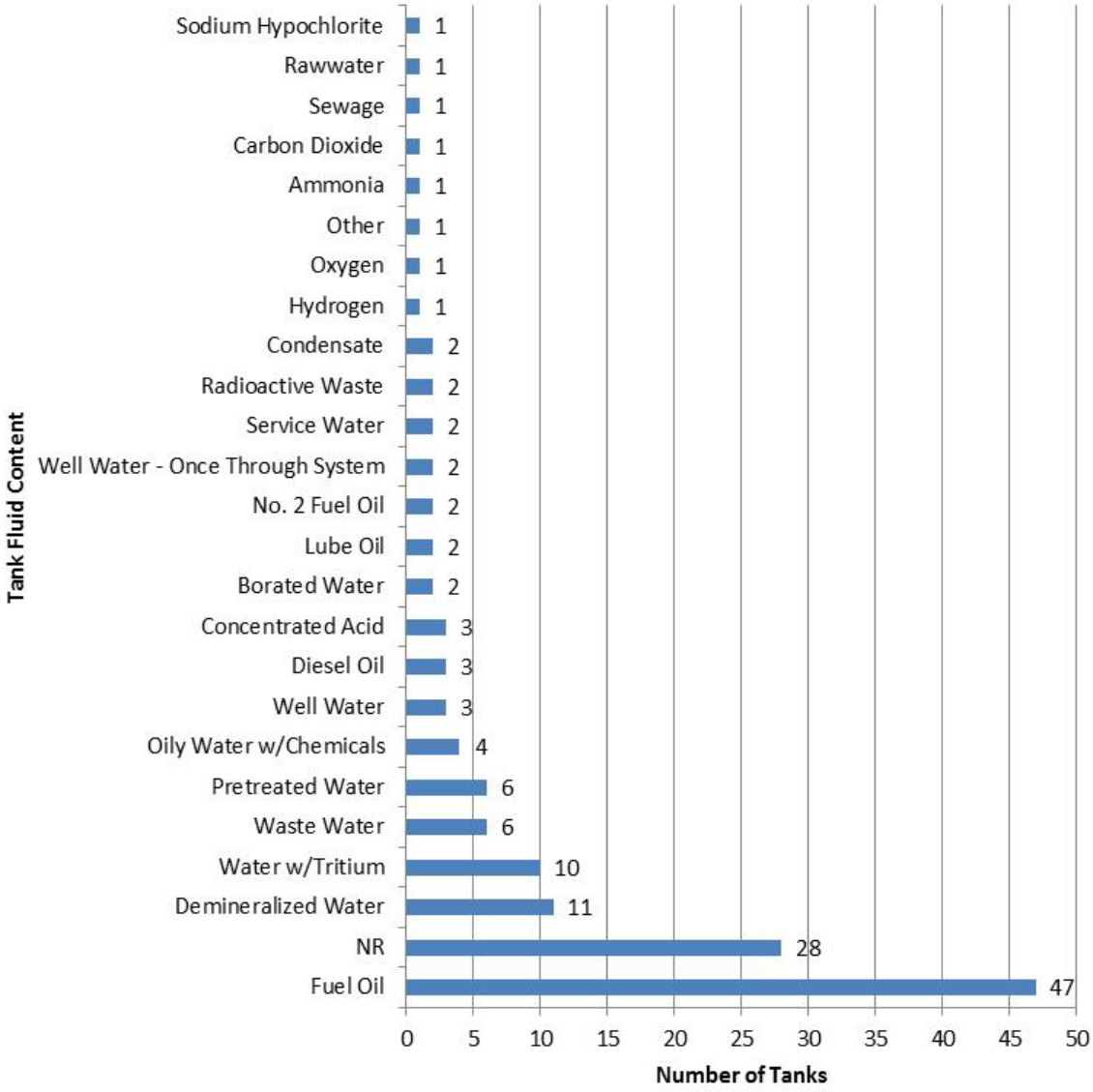

Figure A-22
Summary of Combined Responses, by Contents

A.3.3 Internal Coating (Lining)

The following plot shows the distribution of the tank internal coatings. Fifty-seven tanks (40%) have no internal coating, 39 tanks (27%) provided no data and 22 tanks (15%) have a variety of epoxy coating.

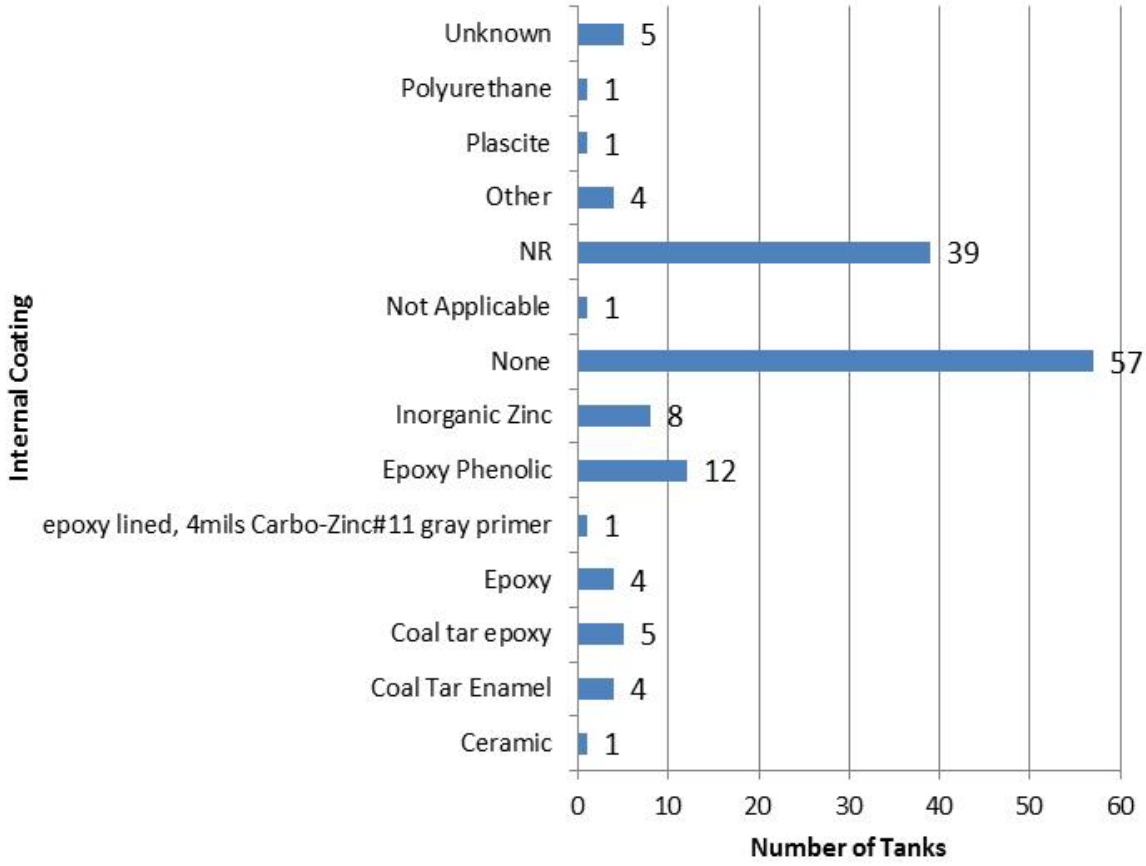

Figure A-23
Summary of Combined Responses, by Internal Coating (Lining)

A.3.4 External Coating

The following plot shows the distribution of tank external coatings. Thirty-five tanks (25%) have variations of epoxy coatings, 16 tanks (11%) have no external coating, and 42 tanks (29%) provided no data for the external coating.

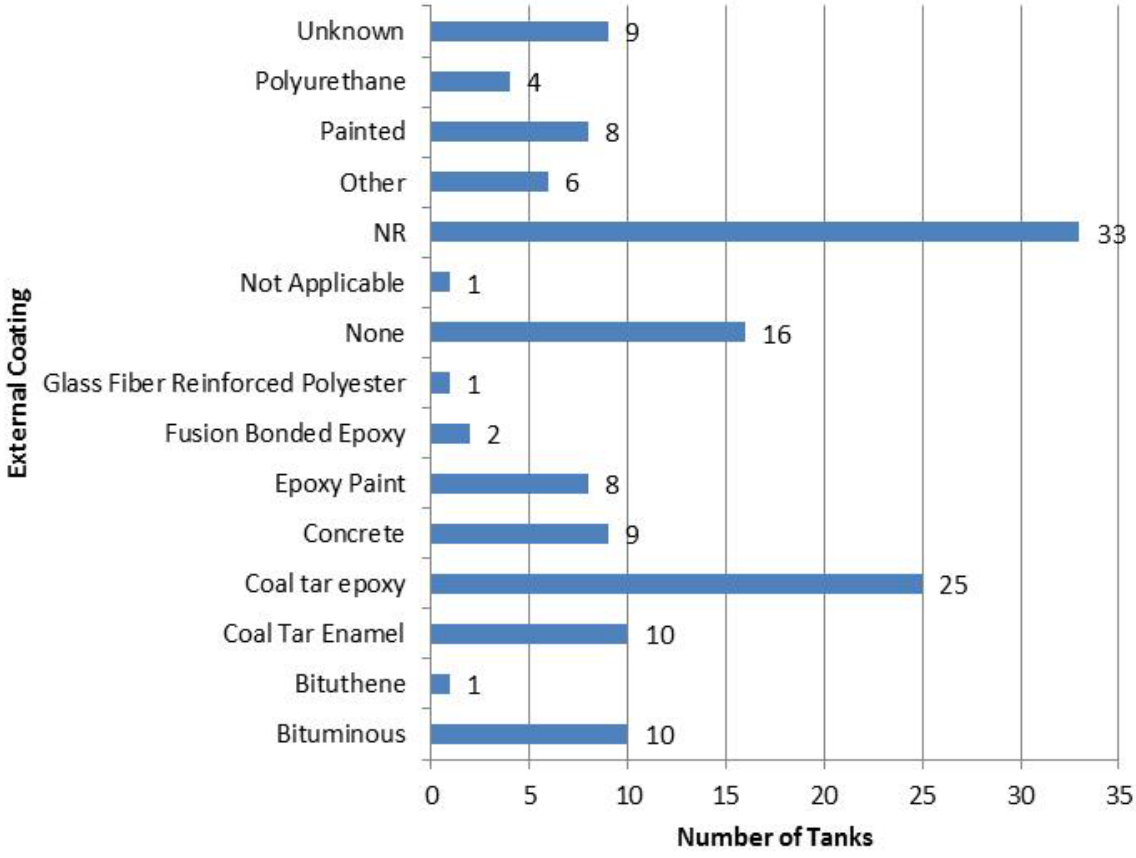

Figure A-24
Summary of Combined Responses, by External Coating

A.3.5 Environment

This section reviews the environment surrounding the tank. For this section, the following definitions are applied:

1. **Above:** The tank is located completely above ground and the bottom may or may not be in contact with the soil. Note that this definition differs slightly from the definition of an AST given in Section 1.3 and used in the rest of the report. This is because the definition for "Partially Buried, below, covers those tanks with up to 10% of their volume below grade level.
2. **Partially Buried:** The bottom and lower part of the sides of the tank are below grade and in contact with soil.
3. **Buried:** The tank is completely below grade and is in contact with soil.
4. **Under:** The tank is below grade and is NOT in contact with soil.

The following plot shows the distribution of the tank environment. A majority of the buried tanks are diesel fuel for emergency generators which are typically located in a vault and buried in soil. Three (3) tanks (2%) are underground, and not in contact with soil, but may be exposed to standing water. Twenty-seven tanks provided no data for the tank environment and thus were listed as "Unknown".

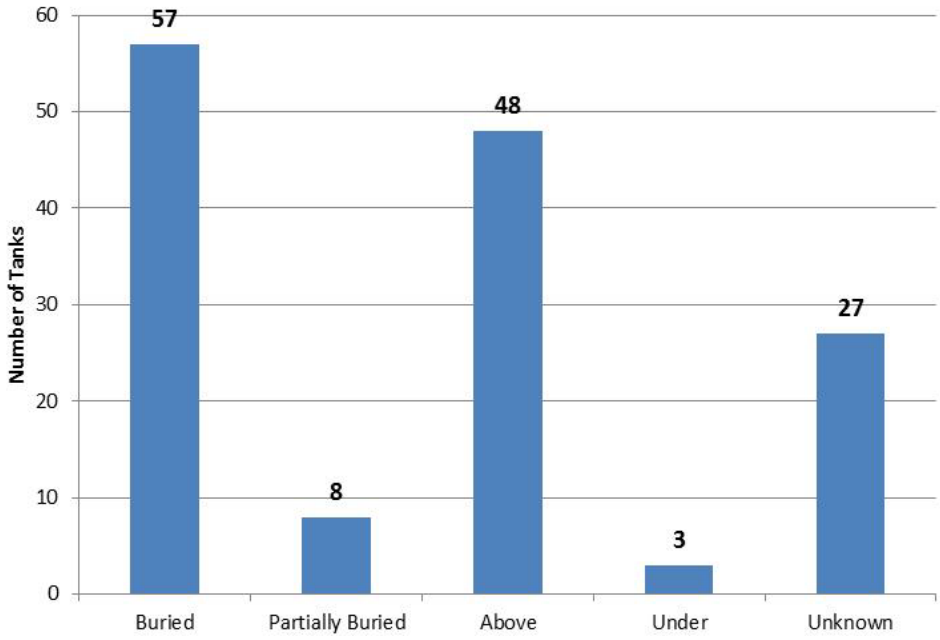

Figure A-25
Summary of Combined Responses, by Environment

A.3.5 Age

The following plot shows the distribution of tank age. The largest groups of tanks are between 30-35 and 40-45 years old (28 tanks (20%), for each), eleven (11) tanks (8%) were installed in the last ten years. Thirty-three tanks (23%) have been in service for over 40 years, and 26 tanks (18%) provided no data for in-service date.

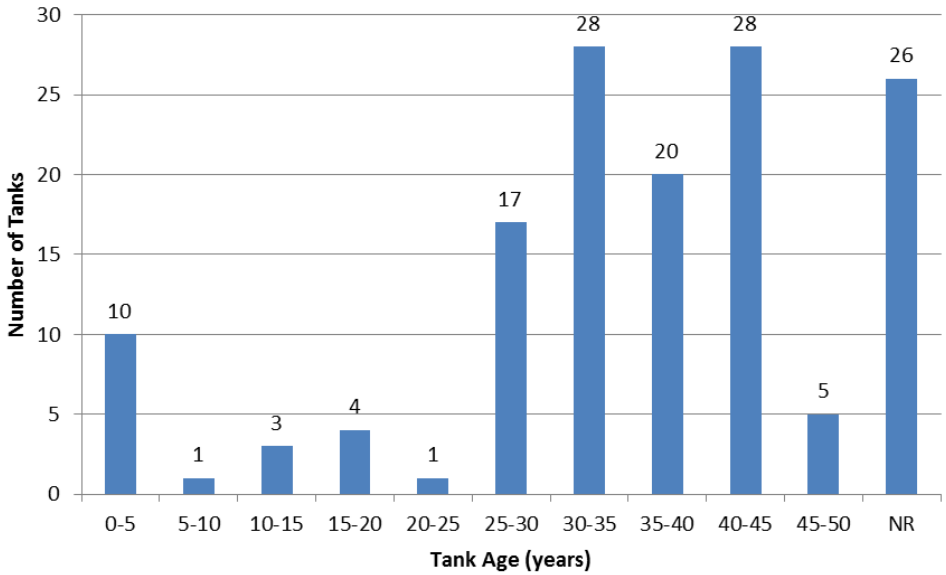

Figure A-26
Summary of Combined Responses, by Age

A.3.6 Operating Conditions

A.3.6.1 Pressure

The following plot shows the distribution of the tank operating pressures. Assuming that all values less than or equal to 15 psig are atmospheric, there are 63 tanks (45%) that are not pressurized. Eight (8) tanks (6%) appear to be pressurized, and should be considered vessels. These tanks are included in the analysis, but may be separated in the future if vessels are to be treated differently from an inspection standard. Sixty-four tanks (45%) provided no data for the operating pressure.

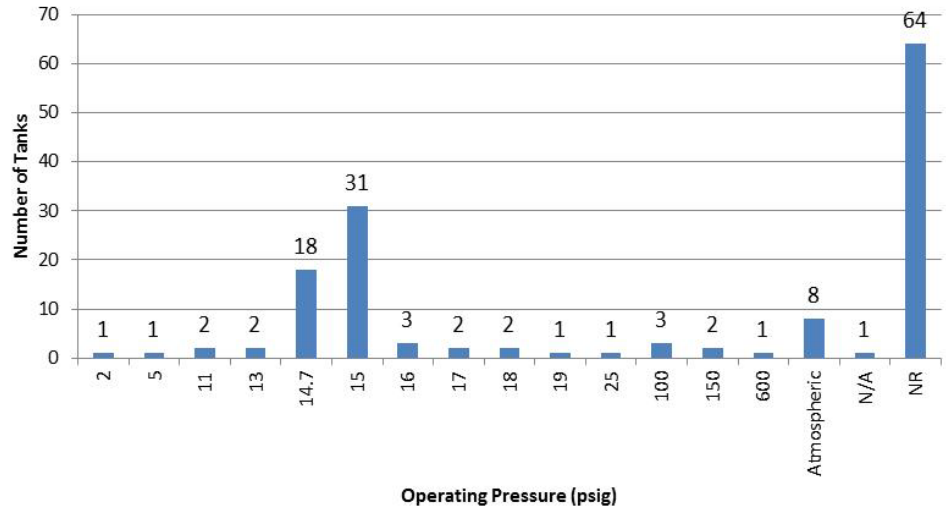

Figure A-27
Summary of Combined Responses, by Operating Pressure

A.3.6.2 Temperature

The following plot shows the distribution of the tank operating temperatures (in degrees Fahrenheit). Assuming that temperatures between the ranges of 50-75 degrees (inclusive) are considered ambient, there are 92 tanks (64%) that operate at ambient temperature. Several tanks had negative operating temperatures, and are believed to have Hydrogen and Oxygen as the contents. Twenty-eight tanks (19%) did not provide data for the operating temperature.

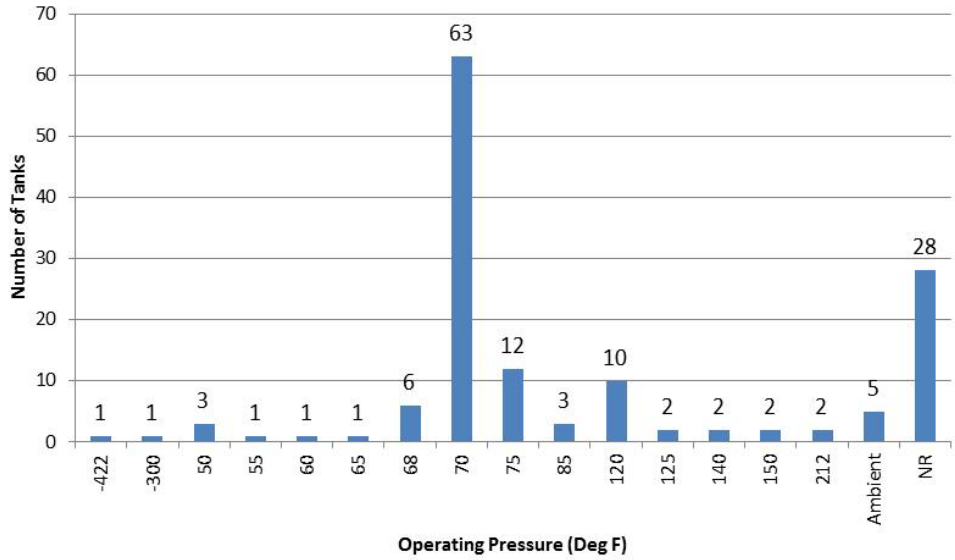

Figure A-28
Summary of Combined Responses, by Operating Temperature

A.3.7 Orientation

This section relays the data in relation to tank orientation, vertical or horizontal. It is presumed that horizontal tanks would have more surface area in contact with the fluid, and thus be more prone to corrosion issues. While this question was not asked on the survey, it was derived from notes, inspection information, and information regarding whether the tank was buried or on grade. This information is available from the tank databases and was used for the remaining tanks.

The following plot shows the distribution of the tank orientation. Forty-nine tanks (34%) are vertical. Sixty-seven tanks (47%) are horizontal. The orientation of the remaining tanks (27%) is unknown.

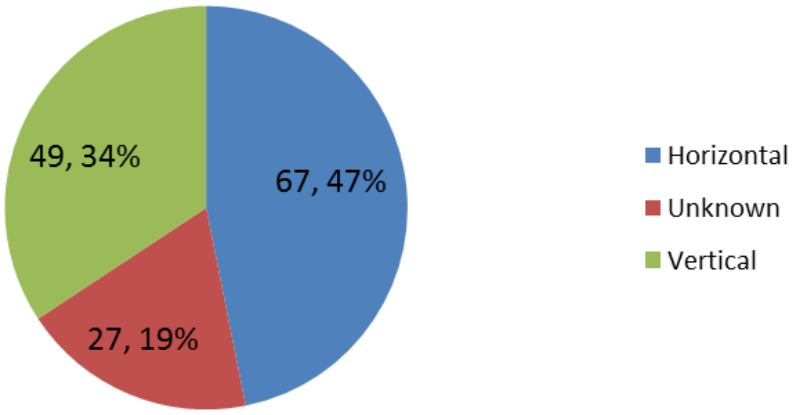

Figure A-29
Summary of Combined Responses, by Tank Orientation

A.3.8 CP Coverage

A.3.8.1 Internal CP

The UPTI database does not include a way to distinguish between internal or external CP systems. All tanks represented by the UPTI database were assumed to be addressing external CP systems only, and any internal CP system was assumed to be Unknown. This section addresses the details of the reported internal CP systems from the survey responses only.

A.3.8.2 Internal System

The plot below shows the distribution of the tank internal CP systems. From the survey responses, 15 tanks (10%) did not have an internal CP system. Twenty-six tanks (18%) did not provide data for the internal CP System. No tanks were shown as having an internal CP System.

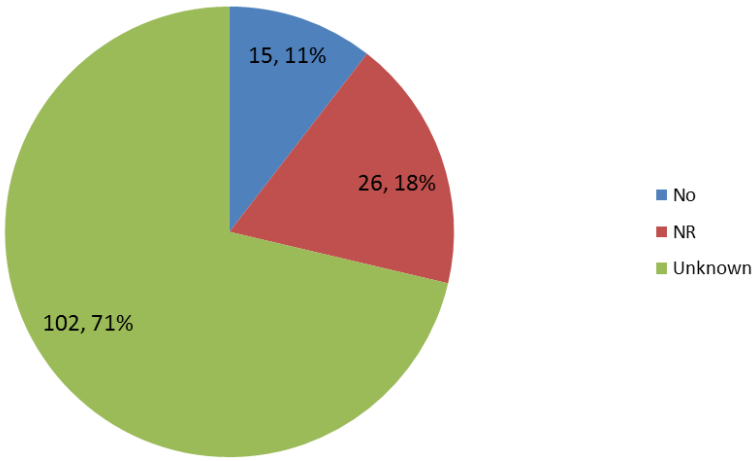

Figure A-30
Summary of Combined Responses, by Internal CP System

A.3.8.3 CP Criteria

While there were no tanks identified as having an internal CP System, the following plot shows several defined criteria.

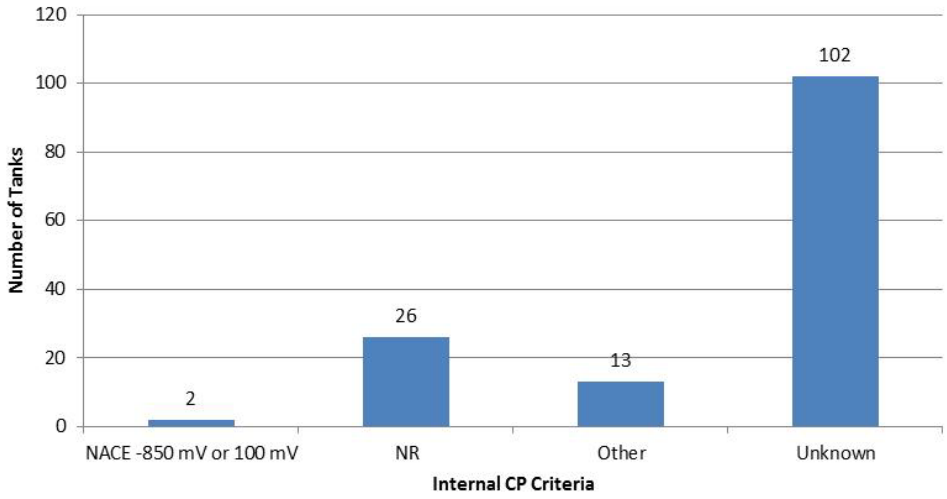

Figure A-31
Summary of Combined Responses, by Internal CP Criteria

A.3.8.4 Historical Operations of Internal CP Systems

While there were no tanks identified as having an internal CP system, the following plot indicates that several tanks have an internal CP system that has worked historically.

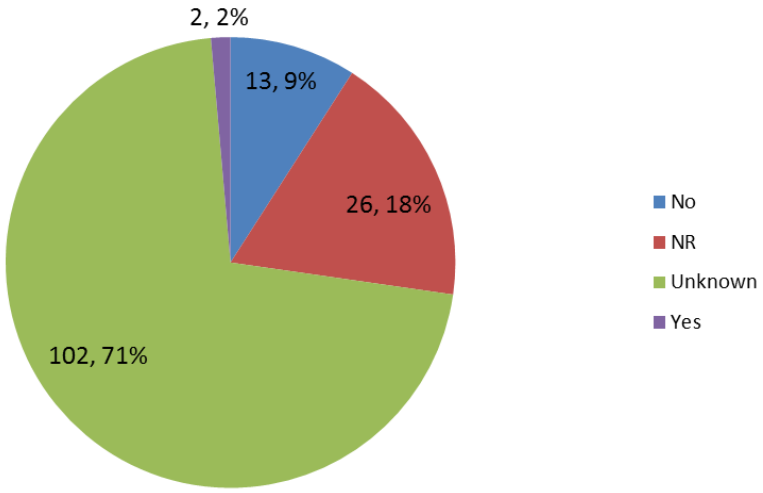

Figure A-32
Summary of Combined Responses, by Historical Operation of Internal CP Systems

A.3.8.5 External CP

A majority of tanks were reported as having an external CP System. This section details the information regarding those systems.

A.3.8.6 External CP System

The following plot shows the distribution of the tank external CP Systems. Seventy-nine tanks (55%) were reported as having an external CP System. Twenty-six tanks (18%) provided no data regarding the external CP System.

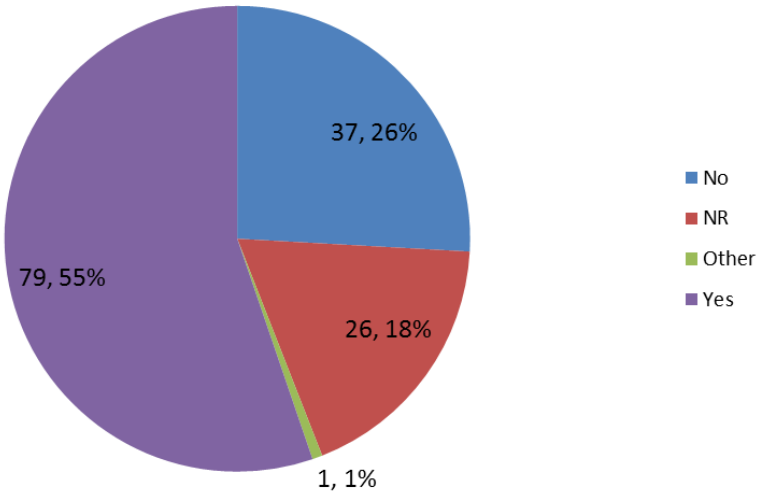

Figure A-33
Summary of Combined Responses, by External CP System

A.3.8.7 Type of External CP System

The following plot shows the distribution of the external CP system types. Thirty-one tanks (22%) have some form of Impressed Current systems. Four (4) tanks (3%) employ a sacrificial anode. Seventy tanks (49%) provided no data for the type of external CP System.

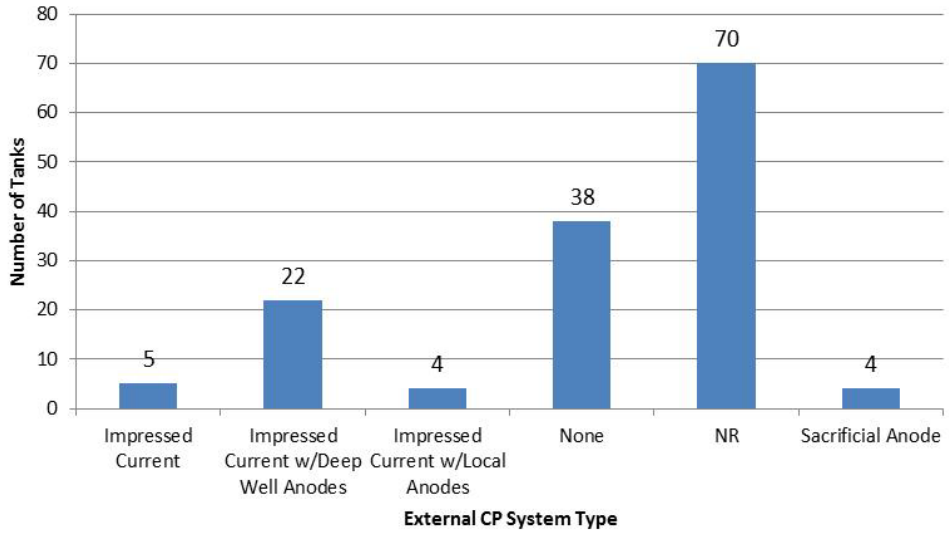

Figure A-34
Summary of Combined Responses, by External CP System Type

A.3.8.8 Criteria of External CP System

The following plot shows the distribution of external CP system criteria. Ninety-one tanks (64%) provided no data regarding the external CP system criteria. Twenty-five tanks (17%) employ the -850 mV Instant-Off criteria.

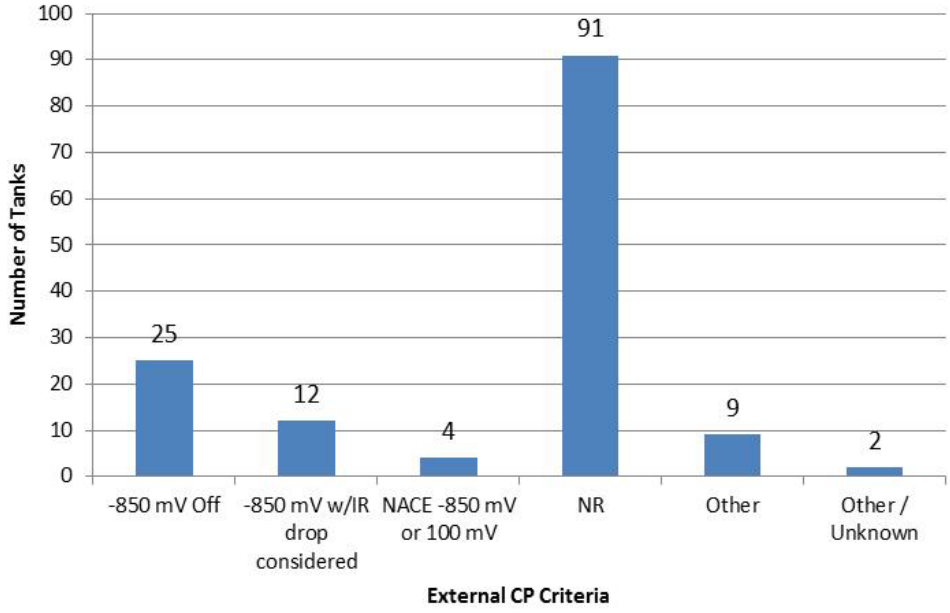

Figure A-35
Summary of Combined Responses, by External CP Criteria

A.3.8.9 Historical Operation of External CP System

The following plot shows the distribution of the historical operating condition of the external CP Systems. Six (6) tanks (4%) indicate that the external CP system has worked historically. One-hundred two tanks (71%) provided no data regarding the historical operation or the historical condition is unknown.

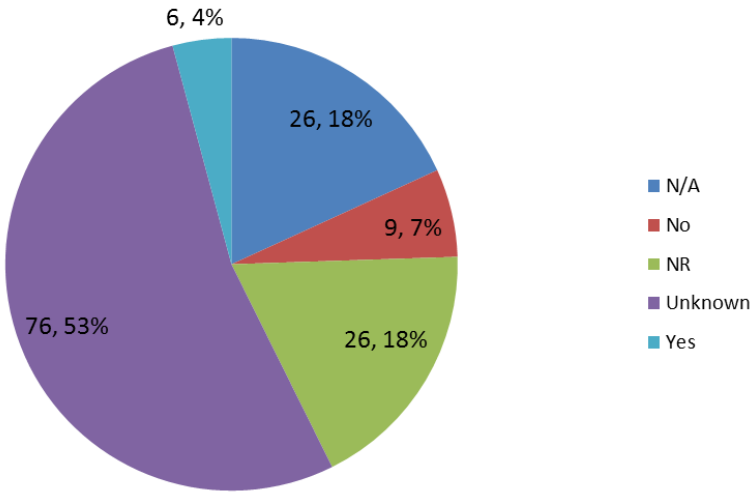

Figure A-36
Summary of Combined Responses, by Historical Operation of External CP Systems

A.3.8.10 Soil Resistivity of In-Contact Soil

The following plot shows the distribution of the soil resistivity in the area around the tank. Five (5) tanks (3%) have a resistivity of less than 10,000 ohm-cm. One-hundred twenty-four tanks (87%) provided no data for soil resistivity or it is unknown.

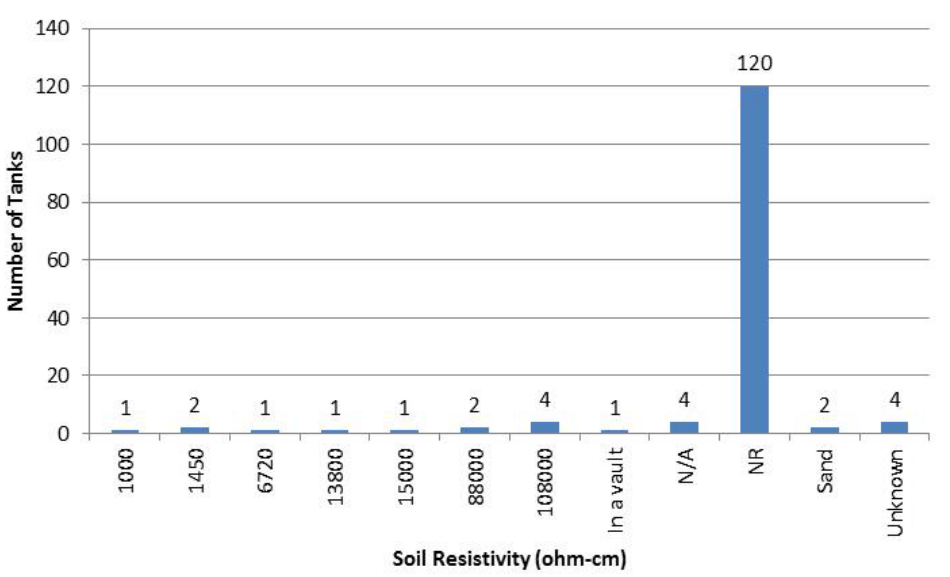

Figure A-37
Summary of Combined Responses, by Soil Resistivity

A.4 Tank Inspection Results

This section reviews the inspection results provided by both the survey and the tank inspection databases. The following table shows the breakdown of tanks and inspection records used for analysis in this section.

Table A-1
Breakdown of Tank and Inspection Records

Data Source	Tank Records	Complete Inspection Records
Complete Survey Response	14	14
Partial Survey Response	27	0
Tank Database – No Inspections	86	0
Tank Data – With Inspections	16	77
Totals:	143	91

Of the 143 tanks analyzed in this report, 30 had at least one inspection. Twelve (12) tanks had multiple inspections. A total of 91 complete inspection records were analyzed in this section. The inspection records for Diesel Fuel Oil made up 77% of the data (the largest of all tanks inspected).

Some of the sections below will indicate the data for the tanks (not multiple inspections). Some will indicate all the tanks plus the multiple inspections (a total of 204 records overall (143 tanks + 77 inspection records -16 tanks already counted = 204 records total)).

A.4.1 History of Leaks

The following plot shows the reported history of leaks for the sampled tanks (143 tanks total). Ninety-six tanks (67%) have no history of leaks. Two tanks (2%) indicate a leak sometime in the service life of the tank. Forty-five tanks (31%) provided no data or an unknown history of leaks.

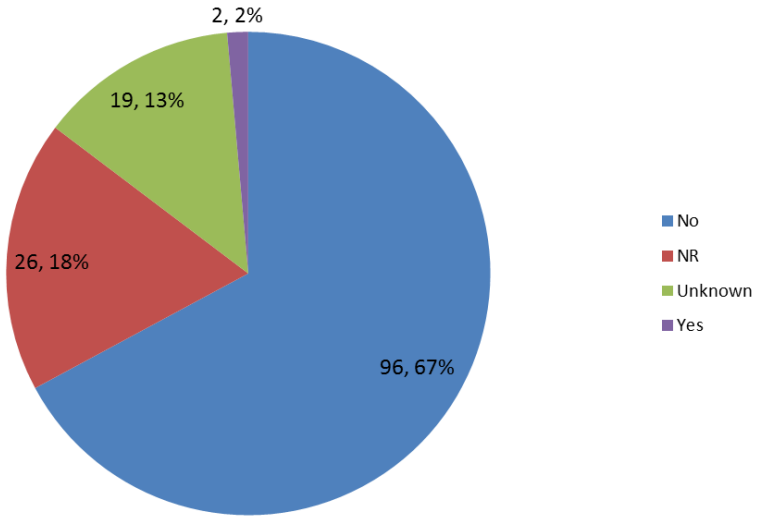

Figure A-38
Summary of Combined Responses, by History of Tank Leaks

A.4.2 Condition Assessment Plan

The following plot shows the distribution of condition assessment plans for all the tanks listed in the survey responses and the UPTI databases (143 tanks total). The UPTI database does not provide a field to indicate the condition assessment plan; those tanks are reflected with a value of Unknown.

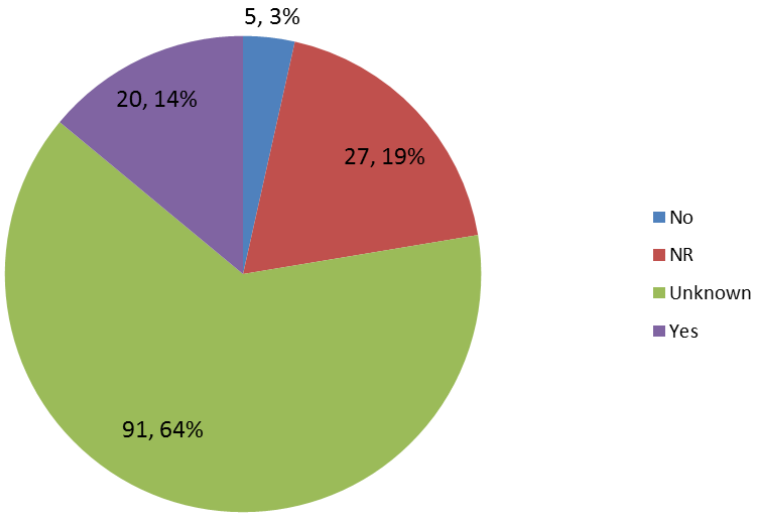

Figure A-39
Summary of Combined Responses, by Condition Assessment Plan

A.4.3 Service Life Prediction Model

The following plot shows the distribution of the use of a service life prediction model used for each tank (143 tanks total). The UPTI database does not provide a field for this value; those values are shown as Unknown.

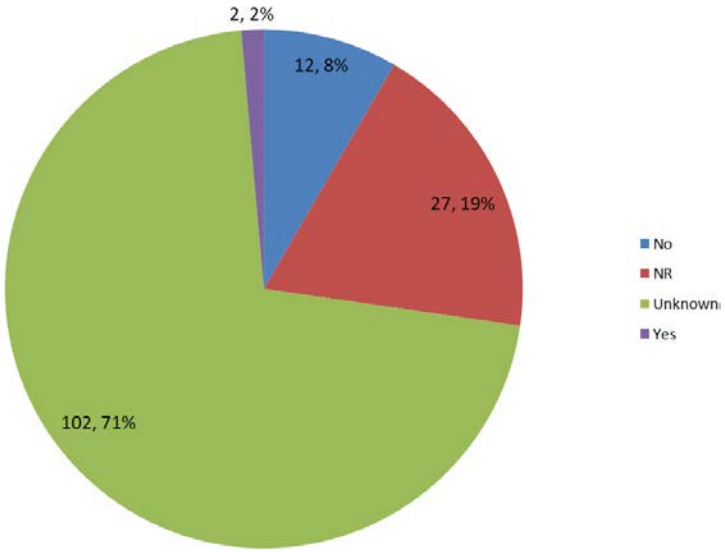

Figure A-40
Summary of Combined Responses, by Use of Service Life Prediction Model

A.4.4 Inspectors

The following plot shows the distribution of the inspectors used for the tank inspections (204 records total). The UPTI database does not provide a field to indicate who conducted the inspection; those results are presented as "Unknown" unless it was indicated in a comments or remarks field.

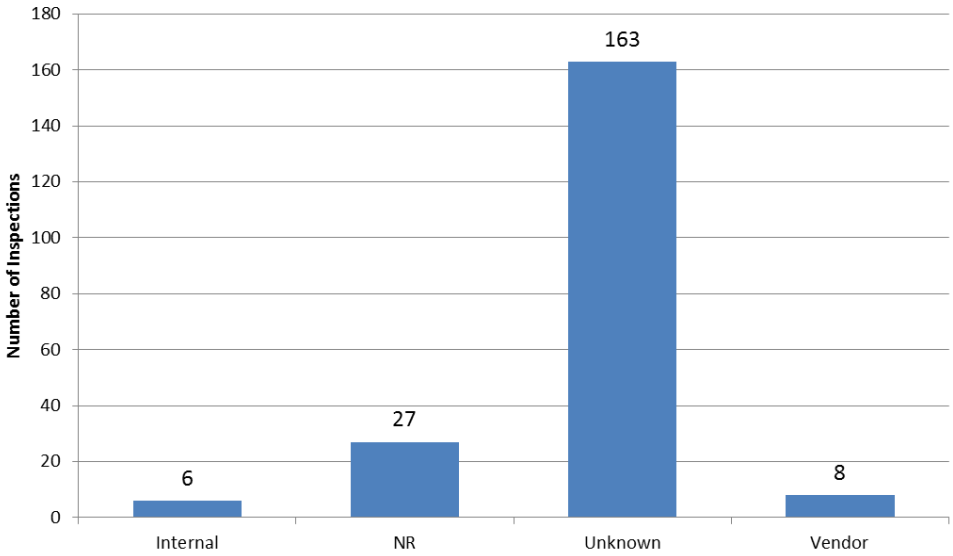

Figure A-41
Summary of Combined Responses, by Tank Inspectors

A.4.5 Inspection Reason

The following plot shows the distribution of the reasons for the inspections (204 records total). Only six (6) records (3%) indicate the inspection was done for regulatory reasons. One-hundred seventy-eight records (87%) provided no data for this value.

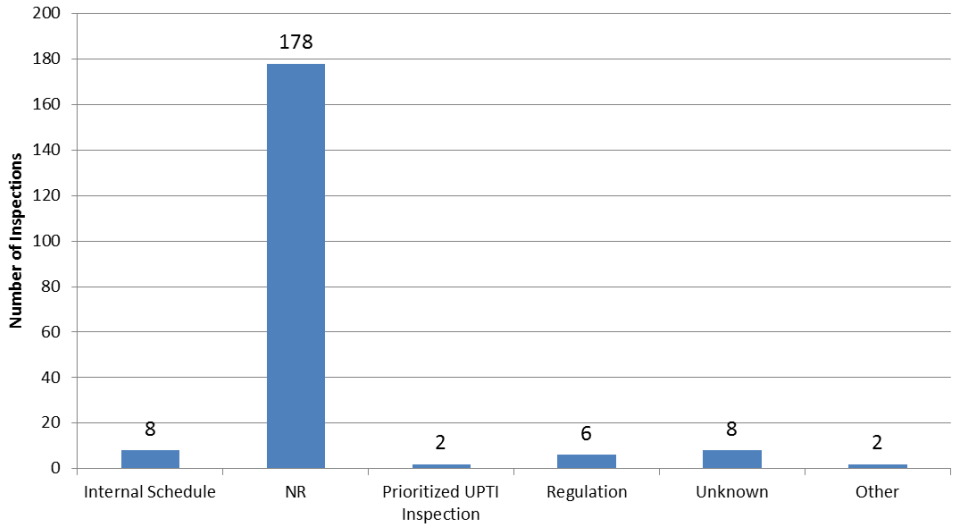

Figure A-42
Summary of Combined Responses, by Reason for Inspection

A.4.6 Techniques

The following plot shows the distribution of the inspection techniques reported for all the inspections (204 records total). Twenty-seven inspection records (13%) had no data on the inspection techniques used. It is unclear whether 86 tanks (60%) have been inspected, as no inspection details were provided for those tanks (shown as 86 inspections of type Unknown in Figure A-42).

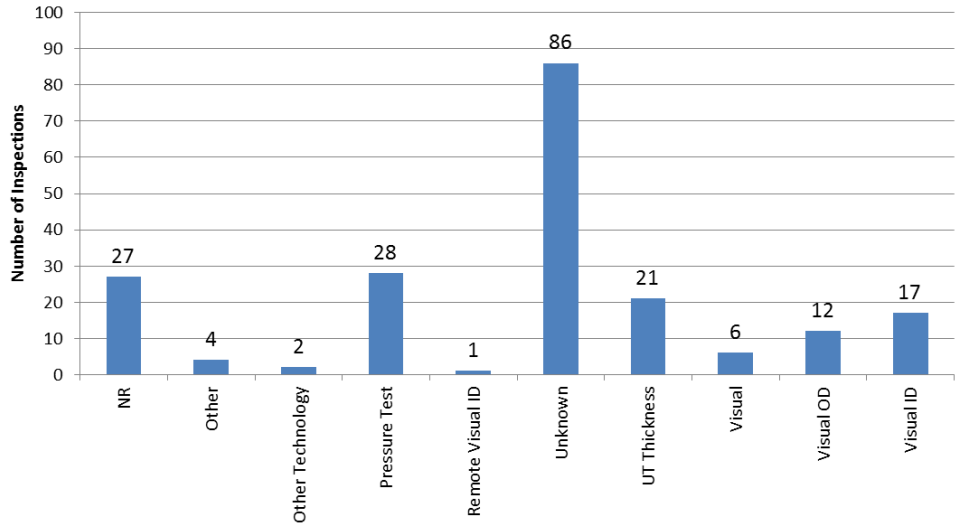

Figure A-43
Summary of Combined Responses, by Inspection Type

A.4.7 Frequency

The following plot shows the average inspection frequency by inspection technique for the twelve (12) tanks that had multiple inspection records. Pressure tests (were only found for Diesel Fuel Oil tanks) were conducted, on average, once every 20.66 months. UT Thickness inspections were conducted, on average, every 60.89 months (approximately every five (5) years). Visual OD inspections were conducted, on average, every 10.9 months (essentially once a year). Visual ID inspections were conducted, on average, every 40.46 months.

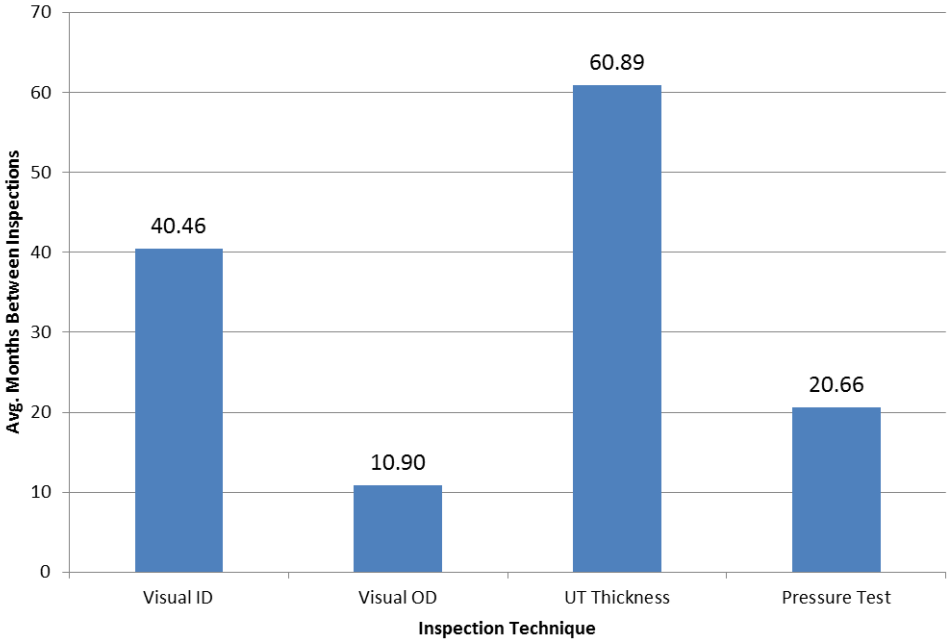

Figure A-44
Summary of Combined Responses, by Months between Inspections, by Technique

Several tanks had only one inspection per technique reported in the data, thus it is unknown what the inspection interval is for that technique. The following plot shows the distribution of the inspection techniques and the number of tanks inspected. For example, eight (8) tanks had one Visual ID inspection, but may have had multiple other types of inspections.

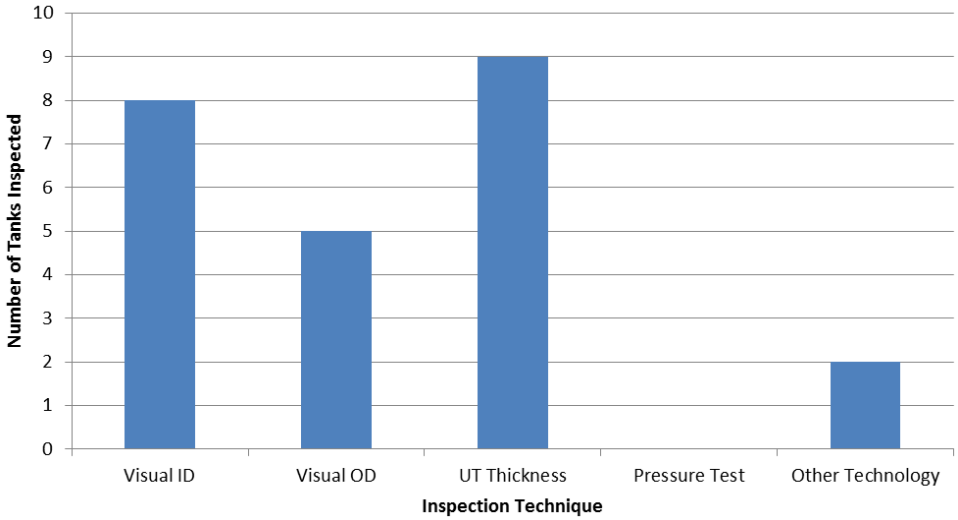

Figure A-45
Summary of Combined Responses, by Inspectoin Technique for Single Inspection

A.4.8 Percent Inspected

The following plot shows the distribution of the percentage of the tank inspected per inspection (204 records total). The survey data asked for amount of tank inspected in surface area, and these values were converted to the percentage of the whole tank. Twenty-seven tanks (19%) had no data for the percentage of the tank inspected. It is unclear if 90 tanks (63%) had inspections, and thus the percentage inspected is unknown. Eleven (11) tanks (8%) were 100% inspected, typically as part of a Visual ID or OD inspection (a total of 40 full inspections for the eleven (11) tanks).

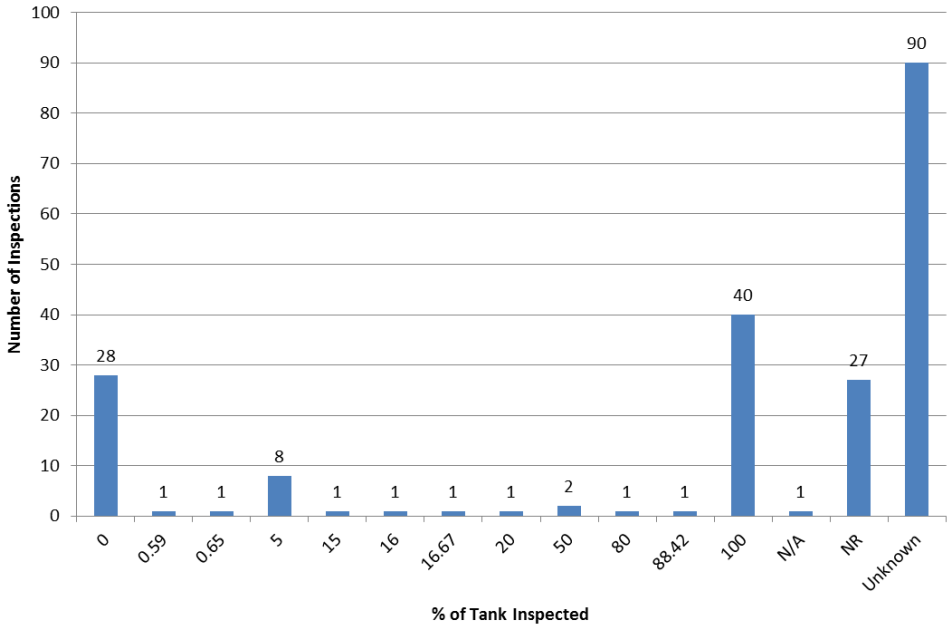

Figure A-46
Summary of Combined Responses, by Percent of Tank Inspected

A.4.9 Inspection Location

The following plot shows the distribution of the tank inspection locations (204 records total). For data from the UPTI database, there is no separate field that tracks where the tank is inspected, unless it is included as part of the comments. If the inspection record indicated it was 100% inspected, it was assumed that the bottom and roof were inspected, but welds and nozzles would be unknown. Tanks that provided no inspection records were assumed to be unknown for all values.

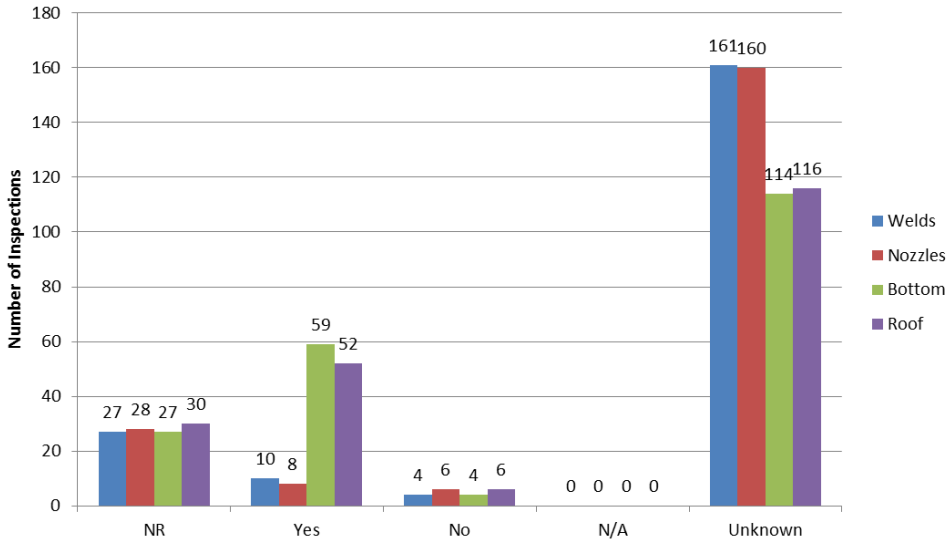

Figure A-47
Summary of Combined Responses, by Tank Areas Inspected

The following plot shows the distribution of the other areas inspected for the tank and includes records for all tanks and inspection records (204 records total). If a UPTI inspection record indicated 100% inspection, it was assumed the sides of the tank were inspected. Forty-three inspection records indicated that the sides were also inspected. Tanks that provided no inspection records were assumed unknown for other areas inspected.

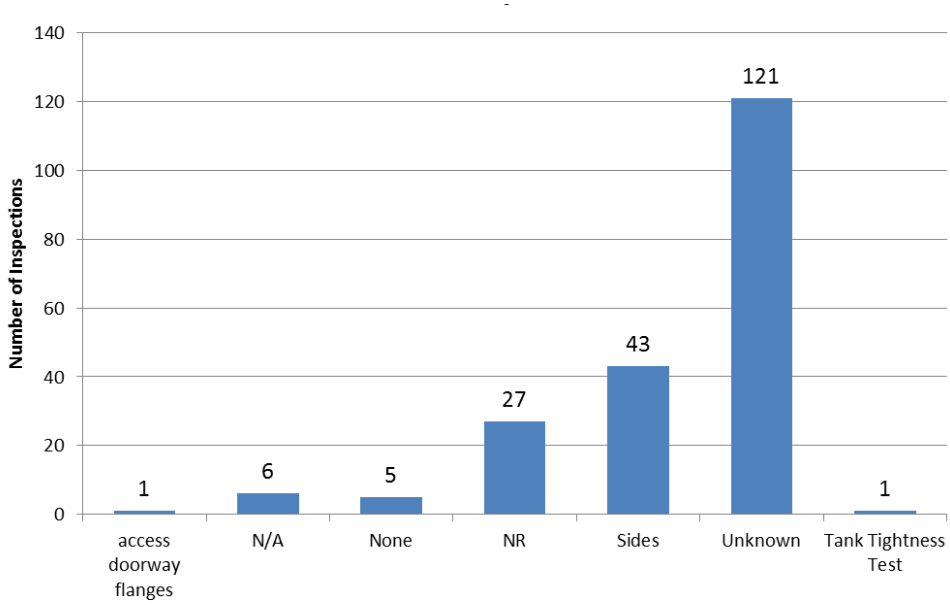

Figure A-48
Summary of Combined Responses, by Other Tank Areas Inspected

A.4.10 Equipment Required

The following plots show the inspection and safety equipment required to perform the inspections (143 unique tanks). The UPTI database does not include a field for this information, and those tanks are reflected with answers of "Unknown".

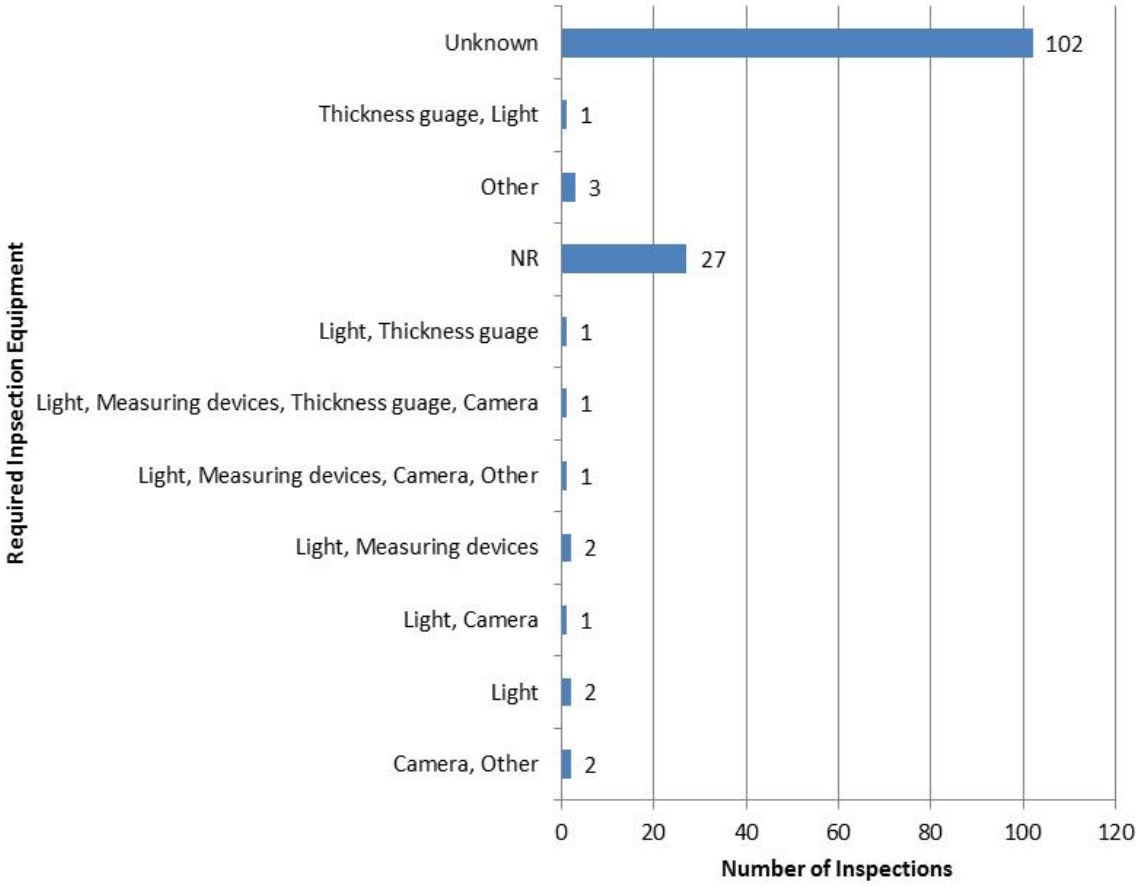

Figure A-49
Summary of Combined Responses, by Inspection Equipment Required

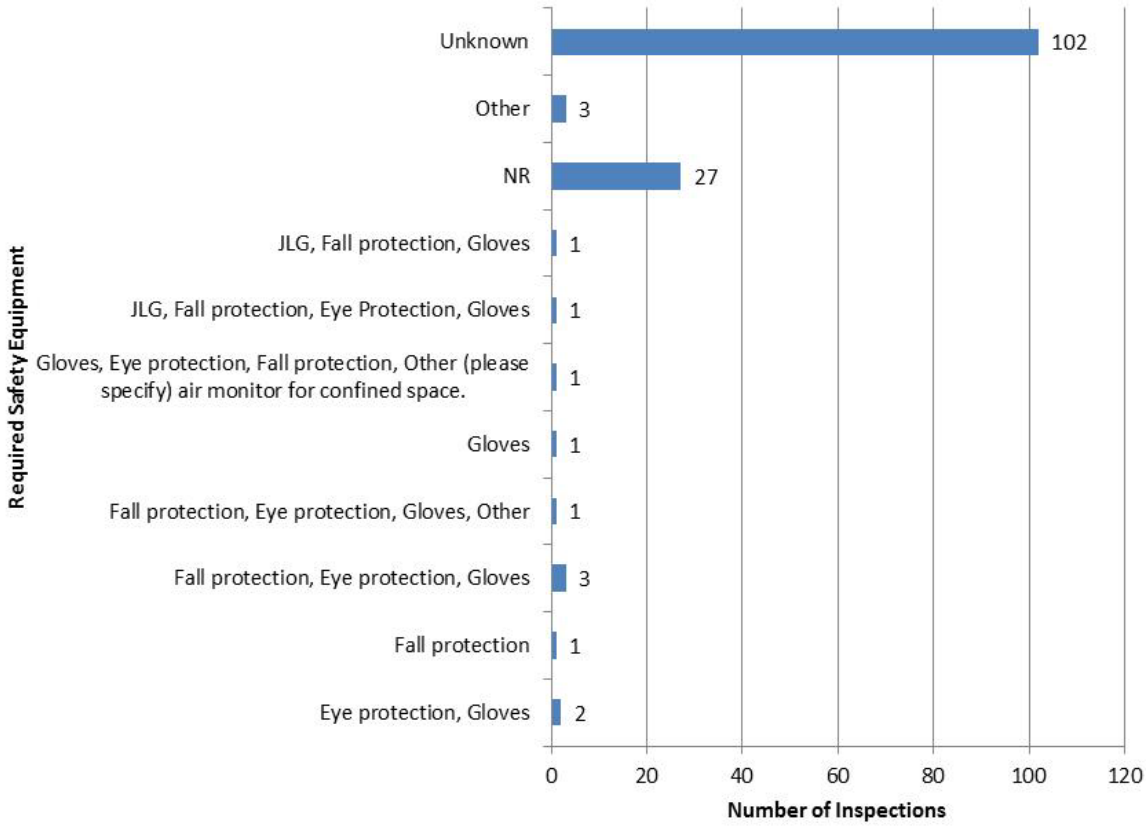

Figure A-50
Summary of Combined Responses, by Safety Equipment Needed

A.5 Occurrence of Degradation

This section reviews the inspection records for indications of degradation. For this section, the answers provided in the survey responses and the tanks that had inspection results, provide the details of the occurrence of degradation (204 records total). If there were no inspections records provided for a tank, degradation was assumed to be unknown. Some tank inspection records may also indicate that degradation was unknown.

A.5.1 Coating Conditions

A.5.1.1 Internal Coatings (Linings)

The following plot shows the distribution of internal coating conditions for the tanks for all inspection records (204 records total). NR means there was no value provided for the coating condition. Unknown means that there was a value entered, but the condition is Unknown. Eighteen (18) records (9%) indicate the coating condition was good. No records indicate a coating condition worse than Good.

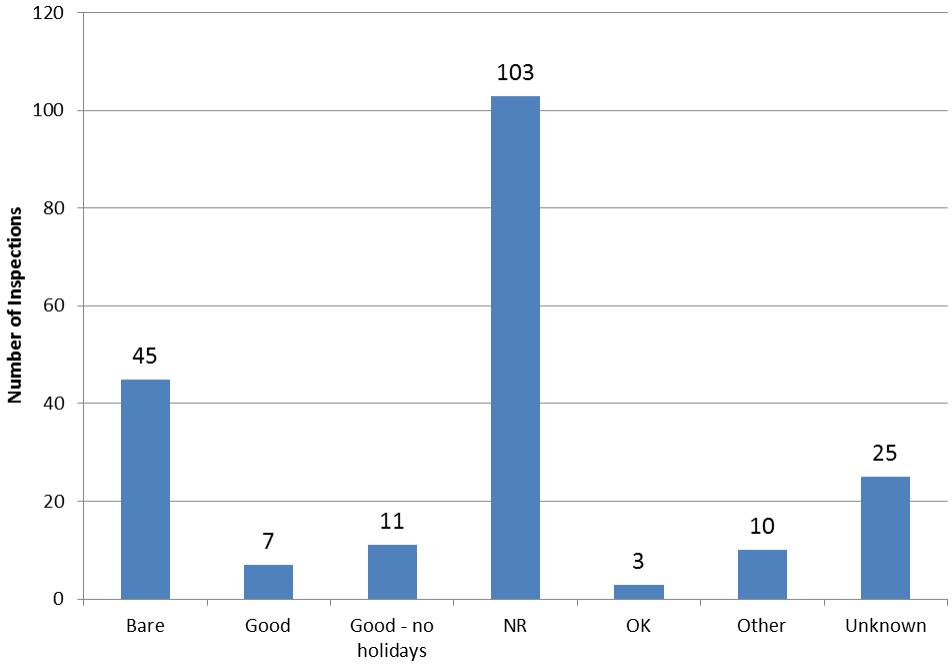

Figure A-51
Summary of Combined Responses, by Internal Coating (Lining) Condition

A.5.1.2 External Coatings

The following plot shows the distribution of the external coating conditions for all inspection records (204 records total). NR means there was no value provided for the coating condition. Unknown means that there was a value entered, but the condition is Unknown. Eighteen (18) records (9%) indicate the coating is in "Good" condition. No records indicate a coating condition worse than "Fair".

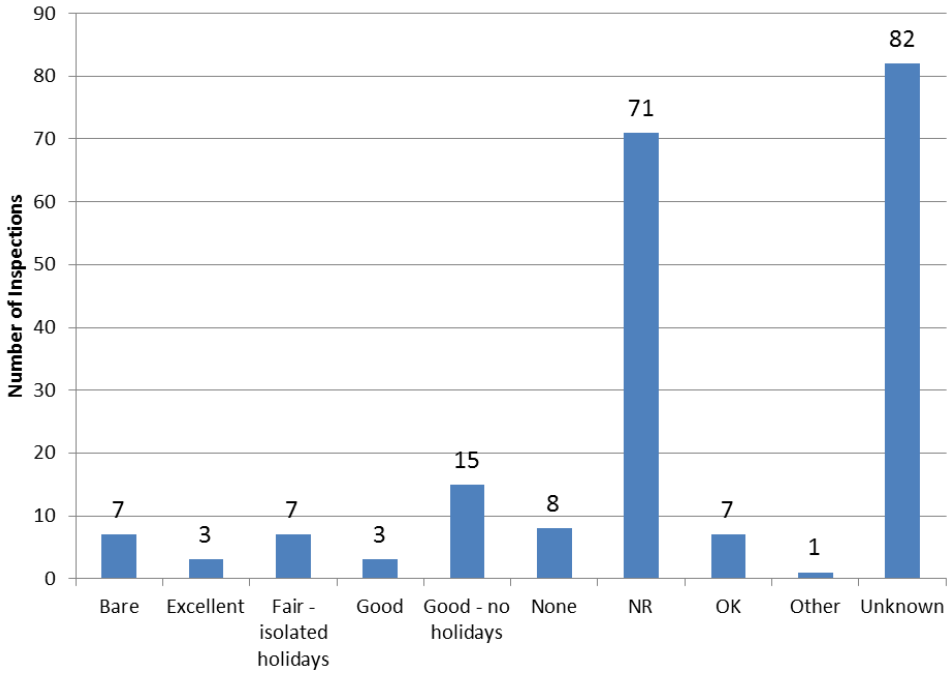

Figure A-52
Summary of Combined Responses, by External Coating Condition

A.5.2 Overall Degradation Results

The following plot shows the overall degradation results for the tank inspection records. Sixteen (16) records (8%) indicated that degradation was found. Thirty-nine inspection records (19%) indicate no degradation was found. One-hundred twenty-two inspection records (60%) have Unknown degradation results.

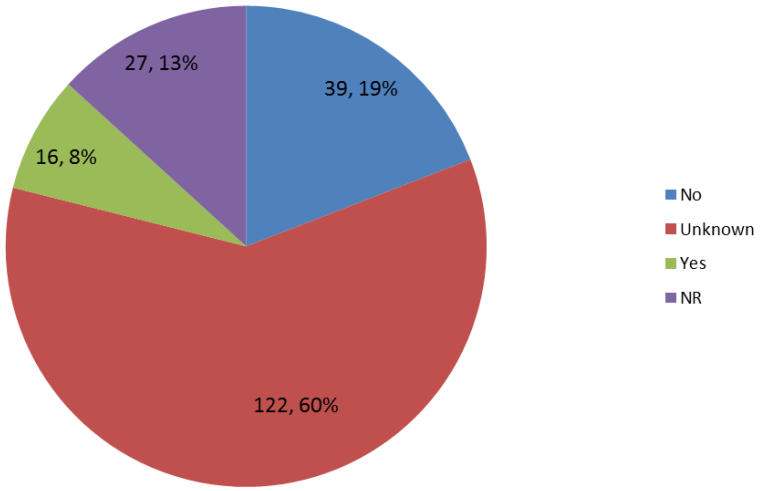

Figure A-53
Summary of Combined Responses, by Degradation Found

A.5.3 Location

A.5.3.1 Internal or External

The following plot shows the distribution of the location of degradations, either internal, external, or both. Twenty-four records (18%) indicate no degradation was found. Fourteen records (7%) indicate internal degradation. One-hundred twenty-three records (60%) indicate "Unknown" results.

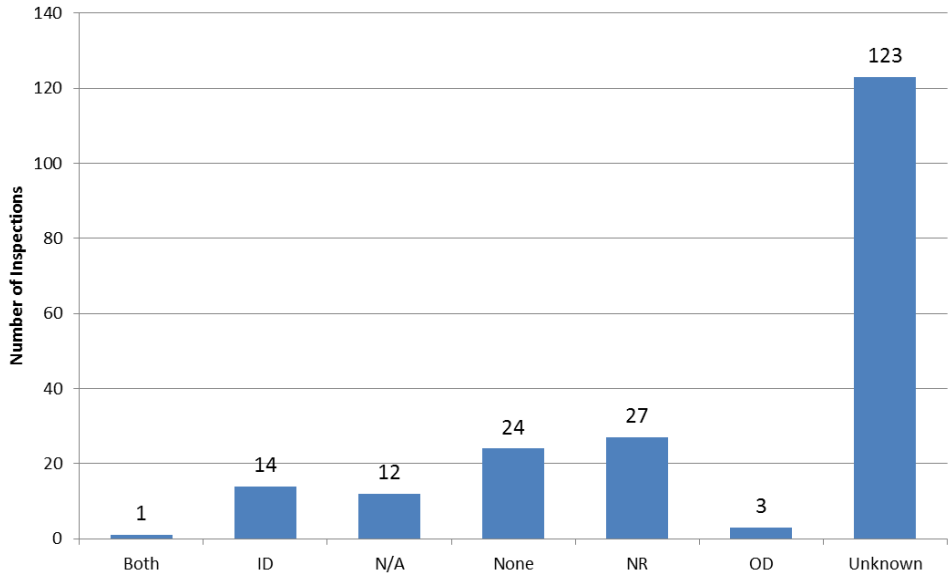

Figure A-54
Summary of Combined Responses, by ID or OD Degradation

A.5.3.2 Location of Degradation

The following plot shows the distribution of the location of the degradation discovered during tank inspections. Eleven (11) records (5%) indicate degradation found on the tank bottom, the largest of all areas reporting degradation.

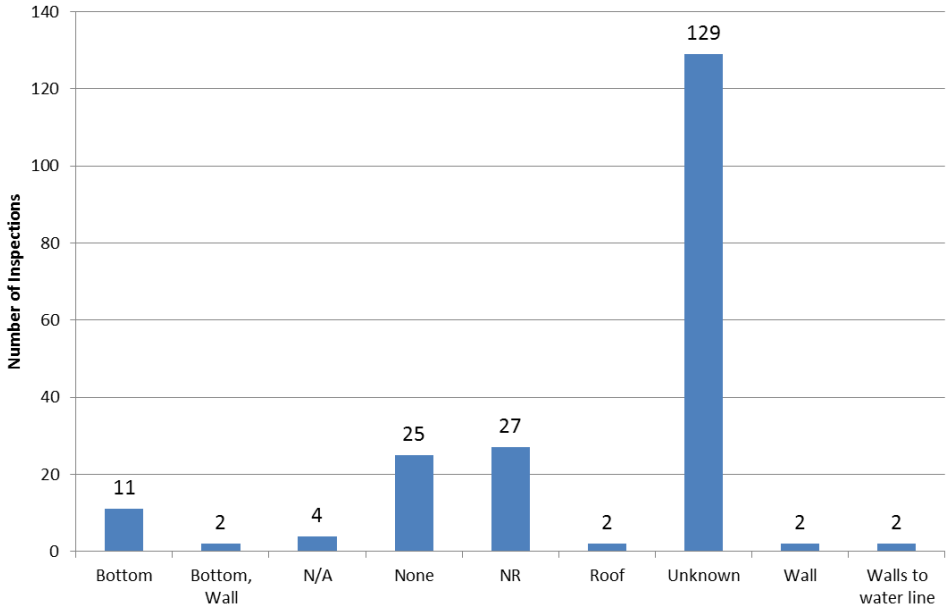

Figure A-55
Summary of Combined Responses, by Location of Degradation

A.5.4 Types of Degradation

The following plot shows the distribution of the types of degradation discovered during tank inspections. Thirteen (13) records (6%) indicate corrosion products. Five (5) records (2%) indicate pitting. Twenty-nine records (14%) indicate no degradation found. Two (2) tanks indicated that sand or silt was found in the bottom of the tank.

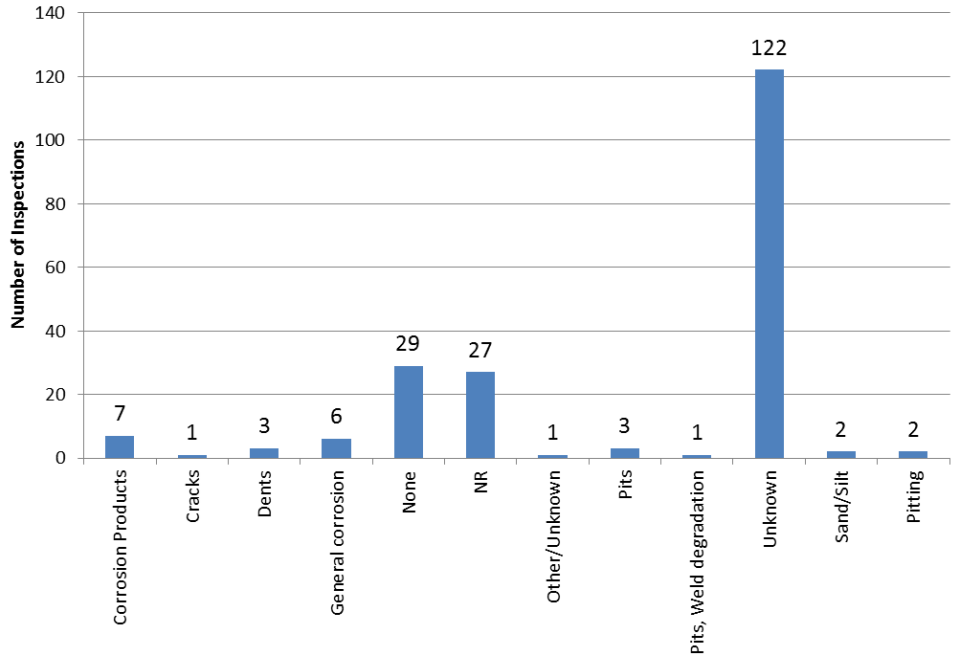

Figure A-56
Summary of Combined Responses, by Degradation Type

A.5.5 Correlation to Failure Mechanisms

This section reviews the inspection results (excludes records where NR was provided for inspection information) and attempts to infer any correlation to the failure mechanisms described in Section A.3. Many of the records contained values of "NR"; thus it is unclear whether the sample size is large enough to infer statistical significance. For this section, the assumption was made that all incomplete records will not materially impact the analysis and were ignored for future analysis. If this assumption is proven to be incorrect, it is suggested that additional research be conducted to provide more complete records for analysis.

The table below shows the results for all inspection records where degradation was found along with the failure mechanism values. Sixteen records (9%) show degradation out of a total of 177 inspection records.

Table A-2
Details for Tanks with Degradation

Degradation Location	Type of Degradation	Inspection Type	Content	Internal Lining	External Coating	Material	CP Present?	Operating Pressure (PSIG)	Operating Temperature (Deg. F)	Orientation	Tank Environment	Tank Age (Yrs.)
ID	Pits	Other	Demineralized Water	None	None	Aluminum	No	Atmospheric	120	Vertical	Above	26
ID	General corrosion	Visual	Demineralized Water	Other	Other	Carbon Steel	No	Atmospheric	Ambient	Vertical	Above	40
Both	Cracks	Visual	Raw water	None	Other	Carbon Steel	No	Atmospheric	Ambient	Horizontal	Partially Buried	33
ID	Pits, Weld Degradation	Visual	Other	Other	Other	Carbon Steel	No	14.7	Ambient	Vertical	Above	39
ID	Corrosion Products	Remote Visual ID	Oily Water w/ Chemicals	None	Unknown	Carbon Steel	No	14.7	70	Horizontal	Under	35
ID	Corrosion Products	Visual ID, UT Thickness	Wastewater	None	Unknown	Carbon Steel	Yes	14.7	70	Horizontal	Buried	4
Unknown	Other / Unknown	UT Thickness	Fuel Oil	None	Coal Tar Enamel	Carbon Steel	Yes	NR	85	Horizontal	Buried	43
OD	Corrosion Products	Visual OD	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
OD	Corrosion Products	Visual OD	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
ID	Sand/Silt	UT Thickness	Fuel Oil	NR	NR	Carbon Steel	Yes	14.7	70	Horizontal	Buried	4
ID	Sand/Silt	Visual ID	Fuel Oil	NR	NR	Carbon Steel	Yes	14.7	70	Horizontal	Buried	4
ID	Pitting	Visual OD	Fuel Oil	NR	NR	Carbon Steel	Yes	14.7	70	Horizontal	Buried	4
ID	Corrosion Products	Visual ID	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	15	70	Horizontal	Buried	26
ID	Corrosion Products	UT Thickness	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	15	70	Horizontal	Buried	26
ID	Unknown	Visual ID	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	15	70	Horizontal	Buried	26
ID	Pitting	UT Thickness	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	15	70	Horizontal	Buried	26

Notes: NR = Not Reported

The following table pertains to the highest contributing failure mechanisms and lists the percent of the inspections where degradation was found and the percent of all inspections.

Table A-3
Highest Contributing Failure Mechanisms for Tanks with Degradation

	Degradation Location	Type of Degradation	Inspection Type	Content	Internal Lining	External Coating	Material	CP Present?	Operating Pressure (PSIG)	Operating Temperature (Deg. F)	Orientation	Tank Environment	Tank Age (Yrs.)
Largest Contributor	ID	Corrosion	Visual ID	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	Atmos.	Ambient	Horizontal	Buried	26
Total	13	7	8	10	11	4	15	9	16	14	13	11	5
% of Degradation Found	81.25%	43.75%	50%	62.5%	68.75%	25%	93.75%	56.25%	100%	87.5%	81.25%	68.75%	31.25%
% of all Inspections	7.34%	3.95%	4.52%	5.65%	6.21%	2.26%	8.47%	5.08%	9.04%	7.91%	7.34%	6.21%	2.82%

From the table above, the following information was inferred from the majority of records for each mechanism:

- A majority of tanks had corrosion products located on the inside of the tank and were discovered using visual inspection.
- The majority of the tanks were constructed from carbon steel, were buried horizontally, had no internal coating, and contained fuel oil at atmospheric pressure and ambient temperature.
- The majority of the tanks have been in service for over twenty-five years and had an external CP System.

The following table shows the results for all inspection records where degradation was not found along with the failure mechanism values. Thirty-nine records show no degradation out of a total of 177 inspection records (22%).

Table A-4
Details for Tanks with No Degradation Found

Degradation Location	Type of Degradation	Inspection Type	Content	Internal Lining	External Coating	Material	CP Present?	Operating Pressure (PSIG)	Operating Temperature (Deg. F)	Orientation	Tank Environment	Tank Age (Yrs.)
ID	Pits	Other	Diesel Oil	None	Other	Carbon Steel	Yes	25	55	Horizontal	Buried	41
ID	General corrosion	UT Thickness	Borated Water	Other	None	Carbon Steel	Yes	N/A	150	Vertical	Above	40
Unknown	Dents	UT Thickness	Demineralized Water	None	None	Carbon Steel	No	100	140	Vertical	Above	32
N/A	General corrosion	UT Thickness	Diesel Oil	None	Coal tar epoxy	Carbon Steel	No	5	120	Horizontal	Buried	32
N/A	General corrosion	Other	Diesel Oil	Coal tar epoxy	Other	Carbon Steel	No	Atmospheric	60	Horizontal	Buried	20
N/A	Dents	Other	Demineralized water	None	None	Stainless Steel	Yes	Atmospheric	140	Vertical	Above	32
N/A	General corrosion	UT Thickness	Demineralized water	None	None	Stainless Steel	No	Atmospheric	150	Vertical	Partially Buried	40
N/A	Pits	Visual	Demineralized water	None	None	Stainless Steel	Yes	600	120	Vertical	Above	26
N/A	Dents	Visual	Borated Water	None	None	Stainless Steel	No	Atmospheric	Ambient	Vertical	Above	31
N/A	General corrosion	Visual	Demineralized water	Other	Other	Carbon Steel	No	Atmospheric	65	Vertical	Above	41
None	None	Visual OD	Fuel Oil	None	Fusion Bonded Epoxy	Double Wall Carbon Steel	No	NR	70	Horizontal	Buried	18
None	None	Visual OD	Fuel Oil	None	Fusion Bonded Epoxy	Double Wall Carbon Steel	No	NR	70	Horizontal	Buried	18
None	None	Visual ID	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	Visual ID	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	Visual OD	Wastewater	NR	Painted	Carbon Steel	Yes	14.7	70	Horizontal	Above	3
N/A	None	Other Technology	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	15	70	Horizontal	Buried	26
N/A	None	Other Technology	Fuel Oil	None	Polyurethane	Carbon Steel	Yes	15	70	Horizontal	Buried	26
N/A	None	Pressure Test	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	31
N/A	None	Pressure Test	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28

Table A-4 (Continued)
Details for Tanks with No Degradation Found

Degradation Location	Type of Degradation	Inspection Type	Content	Internal Lining	External Coating	Material	CP Present?	Operating Pressure (PSIG)	Operating Temperature (Deg. F)	Orientation	Tank Environment	Tank Age (Yrs.)
N/A	None	Pressure Test	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28
None	None	Visual ID	Fuel Oil	None	Fusion Bonded Epoxy	Double Wall Carbon Steel	No	NR	70	Horizontal	Buried	Unk.
None	None	Visual ID	Fuel Oil	None	Fusion Bonded Epoxy	Double Wall Carbon Steel	No	NR	70	Horizontal	Buried	Unk.
None	None	UT Thickness	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	Visual ID	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	UT Thickness	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	Visual ID	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	UT Thickness	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	Visual ID	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	UT Thickness	Fuel Oil	None	Bituminous	Carbon Steel	No	14.7	70	Horizontal	Buried	46
None	None	UT Thickness	Wastewater	NR	Painted	Carbon Steel	Yes	14.7	70	Horizontal	Above	3
None	None	UT Thickness	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	31
None	None	Visual ID	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	31
None	None	Pressure Test	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	31
None	None	UT Thickness	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28
None	None	Visual ID	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28
None	None	Pressure Test	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28
None	None	Pressure Test	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28
None	None	Visual ID	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28
None	None	UT Thickness	Fuel Oil	None	Concrete	Carbon Steel	No	15	50	Horizontal	Buried	28

The following table is limited to the highest contributing failure mechanisms and lists the percent of the inspections where degradation was found, and the percent of all inspections. The first two columns have been removed since no degradation was found.

Table A-5
Highest Contributing Failure Mechanisms for Tanks with No Degradation Found

	Inspection Type	Content	Internal Lining	External Coating	Material	CP Present?	Operating Pressure (PSIG)	Operating Temperature (Deg. F)	Orientation	Tank Environment	Tank Age (Yrs.)
Largest Contributor	Visual ID	Fuel Oil	None	Concrete	Carbon Steel	No	Atmos.	Ambient	Horizontal	Buried	46
Total	13	30	34	12	35	31	31	33	32	31	9
Percent of No Degradation Found	33.33%	76.92%	87.18%	30.77%	89.74%	79.49%	79.49%	84.62%	82.05%	79.49%	23.08%
Percent of all Inspections	7.34%	16.95%	19.21%	6.78%	19.77%	17.51%	17.51%	18.64%	18.08%	17.51%	5.08%

From the table above, the following information was inferred from the majority of records for each mechanism:

- The majority of the tanks were constructed from carbon steel, were buried horizontally, had no internal coating, and contained fuel oil at atmospheric pressure and ambient temperature.
- The majority of the tanks have been in service for over forty-five years and had NO external CP System.

From Tables A-3 and A-4, the only differences appear to be in the CP System protection and the tank age. The majority of older tanks with no external CP system showed no internal degradation than newer tanks. It is unclear whether this finding has statistical significance but it is presented for consideration.

B
PETROLEUM EQUIPMENT INSTITUTE SAMPLE CHECKLISTS FOR DAILY, MONTHLY, AND ANNUAL INSPECTIONS

The Petroleum Equipment Institute (PEI) has written a recommended practice to promote proper inspection, operation, and maintenance of underground storage systems. It is provided to enhance the longevity and trouble-free performance of underground storage tank equipment; promote fire prevention and storage system safety; for protection of human health and the environment, regulatory compliance, early identification of potential equipment problems; and to reduce liability associated with the operation of underground storage systems. The recommended practice is titled, *RP900: Recommended Practices for the Inspection and Maintenance of UST Systems* [11]. The complete Table of Contents for RP900 can be previewed at PEI's website.[10] The following are sample UST checklists available for download by PEI showing examples for daily, monthly, and annual inspections. These forms are available for free at the PEI website.

[10] http://www.pei.org/Portals/0/resources/documents/RP/RP900-08_TOC.final.pdf

B.1 Daily Check List

PEI Recommended Practices 900-08

Appendix A-1: SAMPLE FORM FOR DAILY UST SYSTEM INSPECTION CHECKLIST

Go to *www.pei.org/RP900* for an electronic version of this form

DAILY UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST			
Facility ID#	Facility Name/Address	Level I Qualified Person Signature	Date
If any problem is found, contact:		Contact information:	

Category	Description	PEI/RP900	N/A	Tank 1	Tank 2	Tank 3	Tank 4
Leak Detection		6.4					
Automatic Tank Gauge (ATG)	The power is on	6.4.1.1					
	There are no warning or alarm lights blinking or lit	6.4.1.2					
	There is a liquid measurement for each tank and the reading appears accurate	6.4.1.3					
	The printer has paper and is in working condition	6.4.1.4					
Electronic Leak-Detection Monitor	The power is on	6.4.2.1					
	There are no warning or alarm lights blinking or lit	6.4.2.2					
Mechanical Line-Leak Detector	No customers have complained about slow flow	6.4.3.1					
Daily Inventory	Inventory records are reconciled daily and daily variance is within the guidelines set by the facility owner	6.4.4.1					
Tank Fill Area		6.5					
Fill Cover	Fill cover present, not broken or damaged	6.5.1.1					
	Fill covers are identified by color and located on the correct tank	6.5.1.2					
Spill-Containment Manhole (Spill Bucket)	No dirt, trash, water, or product in the spill-containment manhole	6.5.2.1					
	No cracks, bulges or holes in the spill-containment manhole	6.5.2.2					
	Below-grade containment manhole properly latched (if present)	6.5.2.3					
	Below-grade containment manhole contains oil absorbent material	6.5.2.4					
Fill Pipe	Fill cap in good condition, seals tightly	6.5.3.1					
	No obstruction inside the fill pipe	6.5.3.2					
DESCRIBE ANY DEFICIENCIES HERE:							

Instructions: Mark each tank where no problem is observed with a checkmark: √ If certain equipment is not required and / or not present, mark checklist in the N/A column. If a defect is found, mark the checklist with an "X," describe the problem in the "DEFICIENCIES" section, and notify the appropriate person.. Refer to the section in the PEI Recommended Practices on UST system equipment inspection listed in the 'PEI/RP900' column for additional information. Refer to PEI RP500, *Recommended Practices for Inspection and Maintenance of Motor Fuel Dispensing Equipment*, for inspection procedures that apply to fuel dispensing equipment.

B.2 Monthly Checklist

Appendix A-2: SAMPLE FORM FOR MONTHLY UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST – PAGE 1

Go to *www.pei.org/RP900* for an electronic version of this form

MONTHLY UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST

Facility ID#	Facility Name/Address	Level II Qualified Person Signature	Date

If any problem is found, contact: Contact information:

Category		Description	PEI/RP900	N/A	Tank 1	Tank 2	Tank 3	Tank 4
	Daily Inspections	Complete daily checklist and compare to previously completed daily checklists	7.4.1					
Leak Detection Recordkeeping		**Circle method of tank leak detection: ATG, CIM, SIR, IC, GWM, SVM, MIMT Circle method of piping leak detection: CIM, MPLT, SIR, GWM, SVM, MIMP**	7.5					
	Automatic Tank Gauge (ATG)	Passing tank test report printed and properly filed	7.5.1.1					
	Continuous Interstitial Monitoring (CIM)	Sensor status report printed and properly filed	7.5.2.1					
	Monthly Piping Leak Test (MPLT)	Passing piping leak-test report printed/documented and properly filed	7.5.3.1					
	Statistical Inventory Reconciliation (SIR)	This month's inventory analyzed; last month's results passed and available for inspection	7.5.4.1					
	Inventory Control (IC)	Inventory reconciled and within the company or regulatory standard	7.5.5.1					
	Manual Groundwater (GWM) or Soil Vapor Monitoring (SVM)	Wells sampled and results pass	7.5.6.1					
	Manual Interstitial Monitoring for Tanks (MIMT)	Steel tank: interstitial space checked and found dry	7.5.7.1					
		Fiberglass tank: interstitial space checked and found dry	7.5.7.2					
		Fiberglass tank: level of monitoring fluid within normal range	7.5.7.3					
		For steel and fiberglass tanks, vacuum level is within tolerances	7.5.7.4					
	Manual Interstitial Monitoring for Piping (MIMP)	Tank-top sump inspected and no liquid found	7.5.8.1					
All Tanks			7.6					
	Grade-Level Covers	All covers present, in good condition, seated firmly on the correct tank	7.6.1.1					
	Spill-Containment Manhole	Drain valve in spill-containment manhole in good condition	7.6.2.1					
	Drop Tube	Standard drop tube smooth, no ragged edges, in good condition	7.6.3.1					
		Top edge of coaxial drop tube smooth, round, slightly below the top edge of the fill pipe	7.6.3.2					
	Tank Gauge Stick	Tank gauge stick can be clearly read, is not warped or broken	7.6.4.1					
	Check for Water	No water present in the tank	7.6.5.1					
	Tank Vents	Vent cap present, vent pipe solidly supported and vertical	7.6.6.1					

Appendix A-2: SAMPLE FORM FOR MONTHLY UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST – PAGE 2

Go to *www.pei.org/RP900* for an electronic version of this form

Category	Description	PEI/RP900	N/A	Tank 1	Tank 2	Tank 3	Tank 4
Stage I Vapor Recovery		7.7					
Two-Point (Dual-Point) Vapor Recovery	Cover present, colored orange, seated firmly at grade, not broken, cracked or chipped	7.7.1.1					
	If spill-containment manhole is present, no dirt, trash, water, or product	7.7.1.2					
	If spill-containment manhole is present, no cracks, bulges, or holes	7.7.1.3					
	Vapor recovery cap present, seals tightly	7.7.1.4					
	Poppet of vapor recovery adaptor seals tightly	7.7.1.5					
Observation and Monitoring Wells		7.8					
	Observation well cover is properly identified and secured	7.8.1.1					
Corrosion Protection		7.9					
Impressed-Current Cathodic Protection	Record volt and amp readings, readings consistent with previous months	7.9.1.1					
	Record hour meter reading (if present). Reading increases by about 700 hours each month	7.9.1.2					

DESCRIBE ANY DEFICIENCIES HERE:

Instructions: Mark each tank where no problem is observed with a checkmark: √
If certain equipment is not required and / or not present, mark checklist in the N/A column.
If a defect is found, mark the checklist with an "X," describe the problem in the "DEFICIENCIES" section, and notify the appropriate person.
Refer to the section in the PEI Recommended Practices on UST system equipment inspection listed in the 'PEI/RP900' column for additional information. Refer to PEI RP500, *Recommended Practices for Inspection and Maintenance of Motor Fuel Dispensing Equipment,* for inspection procedures that apply to fuel dispensing equipment.

B.3 Annual Checklist

Appendix A-3: SAMPLE FORM FOR ANNUAL UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST – PAGE 1

Go to *www.pei.org/RP900* for an electronic version of this form

ANNUAL UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST			
Facility ID#	Facility Name/Address	Qualified Technician Signature	Date
If any problem is found, contact:		Contact information:	

Category		Description	PEI/RP900	N/A	Tank 1	Tank 2	Tank 3	Tank 4
Monthly Inspections		Complete monthly checklist and compare to previously completed monthly checklists	8.4.1					
		Monthly inspections reviewed and found adequate	8.4.2					
Submersible Turbine Pump (STP)			8.5					
	All STP	Junction box(es) sealed, not corroded; seal-offs present; intrinsically safe wiring in good condition	8.5.1.1					
		Mechanical line-leak detector properly vented, vent tube not kinked or twisted	8.5.1.2					
		Mechanical line-leak detector passes 3.0 gph test	8.5.1.3					
		Electronic line-leak detector passes 3.0 gph test	8.5.1.4					
		Flexible connector not twisted, kinked, or bent beyond manufacturer's specifications	8.5.1.5					
		Submersible pump and visible piping and fittings show no signs of leaking	8.5.1.6					
		Piping in good condition	8.5.1.7					
	No STP Sump	Submersible pump head, flex connector(s) and other metallic product piping are not in contact with soil or water or are cathodically protected	8.5.2.1					
	STP in Sump	Any water or product removed and disposed of properly	8.5.3.1					
		Sump is free of cracks, holes, bulges, or other defects	8.5.3.2					
		Penetration fittings intact and secured	8.5.3.3					
		Piping interstitial space open to the sump (open piping system only)	8.5.3.4.1					
		Alarm sounds when pressure or vacuum is released (closed piping system only)	8.5.3.4.2					
		Entire interstitial space under pressure or vacuum (closed piping system only)	8.5.3.4.3					
		Sump sensor properly mounted at the bottom of the sump	8.5.3.5					
		Sensor tested and functional	8.5.3.6					

PEI Recommended Practices 900-08

Appendix A-3: SAMPLE FORM FOR ANNUAL UNDERGROUND STORAGE SYSTEM INSPECTION CHECKLIST – PAGE 2

Go to *www.pei.org/RP900* for an electronic version of this form

Category	Description	PEI/RP900	N/A	Tank 1	Tank 2	Tank 3	Tank 4
	Sump lid, gasket, and seals present and in good condition	8.5.3.7					
	Manway cover at grade in good condition, does not touch sump cover, all bolts present, handles and lift mechanism in good condition (as applicable)	8.5.3.8					
Other Tank-Top Sump		8.6					
Other Tank-Top Sump (Same Procedure as STP Sump)	Any water or product removed and disposed of properly	8.5.3.1					
	Sump is free of cracks, holes, bulges, or other defects	8.5.3.2					
	Penetration fittings intact and secured	8.5.3.3					
	Piping interstitial space open to the sump (open piping system only)	8.5.3.4.1					
	Alarm sounds when pressure or vacuum is released (closed piping system only)	8.5.3.4.2					
	Entire interstitial space under pressure or vacuum (closed piping system only)	8.5.3.4.3					
	Sump sensor properly mounted at the bottom of the sump	8.5.3.5					
	Sensor tested and functional	8.5.3.6					
	Sump lid, gasket, and seals present and in good condition	8.5.3.7					
	Manway cover at grade in good condition, does not touch sump cover, all bolts present, handles and lift mechanism in good condition (as applicable)	8.5.3.8					
Other Sumps		8.7					
All Other Sumps (Same Procedure as STP Sump)	Any water or product removed and disposed of properly	8.5.3.1					
	Sump is free of cracks, holes, bulges, or other defects	8.5.3.2					
	Penetration fittings intact and secured	8.5.3.3					
	Piping interstitial space open to the sump (open piping system only)	8.5.3.4.1					
	Alarm sounds when pressure or vacuum released (closed piping system only)	8.5.3.4.2					
	Entire interstitial space under pressure or vacuum (closed piping system only)	8.5.3.4.3					
	Sump sensor properly mounted at the bottom of the sump	8.5.3.5					
	Sensor tested and functional	8.5.3.6					
	Sump lid, gasket, and seals present and in good condition	8.5.3.7					
	Manway cover at grade in good condition, does not touch sump cover, all bolts present, handles and lift mechanism in good condition (as applicable)	8.5.3.8					
ATG Manhole		8.8					
ATG Manhole	Cap in good condition, seals tightly, hole sealed where probe wire goes through	8.8.1					

C
EXAMPLE CHECKLISTS FOR ASTs

The following sections contain checklist examples for monthly and annual inspections. These examples have been resourced from references [4] and [9]. Sections C.1 and C.2 are an overview of the Formal External and Internal inspections to be performed as is recommended by the Steel Tank Institute, at intervals described in Section 3.2 in this document [5]. Section C.3 is publicly available from the Colorado State government [9].

These checklists are not meant to be prescriptive, but to serve as examples to be used as guidance for plant operators in the generation of their own inspection plans and checklists.

C.1 Formal External Inspection Checklist [4]

Item to be Performed	Inspection Technique	Comments
1. General		
Review prior formal periodic inspections, repair and alteration data prior to each inspection for the subject tank as well as those in similar service conditions to identify preexisting and/or potential concerns.	Literature Review	
Inspect AST fabrication against applicable industry standards.	Literature Review	
Inspect coating on AST shell, heads, and supports for coating deterioration.	Visual	
2. Foundation		
Inspect foundation for indications of settlement, cracking, exposed reinforcing steel, or general disrepair.	Visual	
Inspect for standing water and drainage problems	Visual	
3. Supports		
Inspect condition of AST supports. Severe cracking and/or spalling should be evaluated.	Visual	
If there are pad plates between the supports and the shell, inspect their condition.	Visual	
If supports are welded to the shell, inspect welds for signs of stress or deterioration.	Visual	

Item to be Performed	Inspection Technique	Comments
4. Secondary Containment		
Identify and record the type of secondary containment, spill control, and CRDM, if present.	Visual	
Inspect general condition of the containment area including cleanliness, visibility, accessibility and housekeeping that could interfere with future surveillance, inspection, or repairs – day or night.	Visual	
Inspect for liquid in the containment system and CRDM. If liquid is present, find source and report findings.	Visual	
Ensure that drain valves are operable and in good condition.	Visual	
Report penetrations through containment area or areas that are likely to lead failure of secondary containment area.	Visual	
5. Ancillary Equipment		
Inspect piping and piping connections for signs of stress/leakage. Examples include wetted / damaged insulation, severe corrosion, and rusted bolts.	Visual	
Inspect normal and emergency vents and pressure/vacuum devices to verify devices are in good operating condition.	Visual	
Inspect primary and secondary tank level gauges and determine if they are in working order. Inspect alarms for operability.	Visual	
6. Determine Original Shell Thickness		
Measure tank thicknesses of the tank that have no visible corrosion or pitting. Use of an average of these measurements will result in a minimum shell thickness measurement.	UT	
7. Items Specific to Horizontal AST		
Inspect shell plates and welds for indications of exterior corrosion, buckling, distortion, as well as for cracking, pin holes, or mechanical damage.	Visual	
Record UT readings for each plate or shell course in accessible areas without entering the AST. Perform in areas where corrosion is likely to occur. If significant corrosion is detected, investigate further with UTS.	UT/UTS	
Inspect for areas where changes were made post AST fabrication. Inspect for signs of stress and corrosion.		

Item to be Performed	Inspection Technique	Comments
8. Items to Specific to Vertical or Rectangular AST		
Inspect shell surface and attachments as per checklist item 7.		
Inspect vertical AST roof for low areas and signs of standing water. Inspect for paint failure, holes, and corrosion. Take UT readings on roof.	Visual/UT	
9. Items to Specific to Double-wall and Double-bottom AST		
Inspect shell surface and attachments as per checklist item 7.		
Verify leak detection equipment is operational.	Visual	
Check for leaks or the presence of liquid within the interstice.	Visual	
Double-bottom ASTs require UT of areas that are single-wall. Double-wall ASTs do not require UT.	UT	
10. Insulated AST Components		
Remove insulation in areas where mold or moisture is present and examine metal surface for signs of corrosion. Consider wicking effect of corrosion in insulation.	Visual	
If insulation damage is suspected, remove sections of insulation until nature of damage and corrosion is determined.	Visual	
Take UT readings of shell, and if possible, perform at areas marked from previous inspections. If significant corrosion is found, further investigation by UTS is required.	UT/UTS	
11. Final Report		
Include field data, measurements, photos, drawings, tables, and an inspection summary.		
Identify unacceptable conditions and recommend corrective actions. Determine suitability for continued service. Include next scheduled Formal External Inspection and/or Formal Internal Inspection.		

C.2 Formal Internal Inspection Checklist [4]

Item to be Performed	Inspection Technique	Comments
1. General		
A formal internal inspection includes requirements of a formal external inspection.		
For elevated ASTs where all external surfaces are accessible, the internal inspection requirements may be satisfied with an examination from the exterior by using methods such as UTS. For all other scenarios, entry into the AST interior is necessary to inspect condition of all surfaces.	Visual, UTS	
2. Horizontal AST Inspection		
Inspect and record all internal appurtenances and inspect for mechanical damage, corrosion, and deterioration.	Visual	
Inspect welds for cracking with visual inspection, and if necessary, with MT or equivalent.	Visual, MT	
For AST assessment, UTS is preferred to UT when possible.		
If UTS is not possible, take UT measurements of at least 15 points per square foot of the shell that is in contact with the ground. Any questionable areas should be further investigated with UTS.	UT/UTS	
Perform vacuum box examination of questionable welds to test for leaks.	VB	
3. Vertical and Rectangular AST Inspection		
Inspect and record all internal appurtenances and inspect for mechanical damage, corrosion, deterioration.	Visual	
Take UT measurements of internal structures.	UT/UTS	
Inspect welds for cracking with visual inspection, and if necessary with MT or equivalent.	Visual, MT	
If UTS is not possible, take UT measurements of at least 15 points per square foot of the shell that is contact with the ground. Any questionable areas should be further investigated with UTS.	UT/UTS	
Perform vacuum box examination of questionable welds to test for leaks.	VB	

C.3 Examples of Monthly and Annual Inspection Checklists [9]

AST Monthly Visual Inspection Checklist

OPS FacID#:	Facility Name:	Inspection Date:
Street Address:	City:	Zip:
# of Tanks Inspected:	Tank IDs:	

Any item marked "No" requires additional information to describe the condition and date the condition is corrected.

	ITEM	STATUS	COMMENTS / DATE CORRECTED
	PRIMARY TANK and PIPING		
1	Is tank exterior (roof, shell, ends, connections, fittings, valves, etc.) free of visible leaks? *Note: If "No", identify tank and describe leak.*	☐Yes ☐No	
2	Is aboveground piping (valves, fittings, connections, pumps, etc.) free of visible leaks? *Note: If "No", identify location and describe leak..*	☐Yes ☐No	
3	Are ladders/platforms/walkways secure with no sign of severe corrosion or damage?	☐Yes ☐No ☐NA	
4	Are all tank openings properly sealed (capped, plugged, covered, blind flanged, etc.)?	☐Yes ☐No	
5	Is the tank liquid level gauge readable and in good working condition?	☐Yes ☐No ☐NA	
6	Is overfill prevention equipment in good working condition (overfill valve, audible alarm, etc.)? *Note: Verify operation of audible alarms.*	☐Yes ☐No ☐NA	
7	Is the spill container (spill bucket) empty, free of visible leaks, and in good working condition?	☐Yes ☐No ☐NA	
8	Is the primary tank free of water?	☐Yes ☐No	
9	Is the area around the tank (concrete surfaces, ground, containment, etc.) free of visible signs of leakage?	☐Yes ☐No	
10	Cathodic protection system in operating condition and functional? *Note: Inspection required every 60 days only.*	☐Yes ☐No ☐NA	
11	Rectifier reading: Volts _____ Amps _____ *Note: Inspection required every 60 days only.*	☐Yes ☐No ☐NA	
	DOUBLE-WALL TANK		
12	For double-wall tanks, is interstice free of liquid?	☐Yes ☐No ☐NA	
13	For double-wall tanks, is interstitial monitoring equipment in good working condition?	☐Yes ☐No ☐NA	
	CONTAINMENT (Diking/Impounding)		
14	Is the containment free of liquid, debris, combustible materials, and empty or full drums/barrels?	☐Yes ☐No ☐NA	
15	Are dike drain valves closed and in good working condition?	☐Yes ☐No ☐NA	
16	Are containment egress pathways clear and any gates/doors operable?	☐Yes ☐No ☐NA	
	OTHER CONDITIONS		
17	Are there other conditions needing to be addressed for continued safe operation or that may affect the site SPCC Plan?	☐Yes ☐No	

INSPECTOR INFORMATION	
Printed Name:	Signature:

AST Annual Visual Inspection Checklist

OPS FacID#:	Facility Name:	Inspection Date:
Street Address:	City:	Zip:
# of Tanks Inspected:	Tank IDs:	

Any item marked "No" requires additional information to describe the condition and date the condition is corrected.

	ITEM	STATUS	COMMENTS / DATE CORRECTED
	CONTAINMENT		
1	Containment structure in satisfactory condition (diking, impounding, double-wall tank, etc.)?	☐Yes ☐No	
2	Drainage pipes/valves in good working condition for continued service?	☐Yes ☐No ☐NA	
	TANK FOUNDATION / SUPPORTS		
3	Free of tank settlement or foundation washout?	☐Yes ☐No	
4	Concrete pad or ring wall free of cracking or spalling?	☐Yes ☐No	
5	Tank supports in satisfactory condition	☐Yes ☐No	
6	Water able to drain away from tank?	☐Yes ☐No	
7	Grounding strap between tank and foundation/supports in good condition?	☐Yes ☐No ☐NA	
	CATHODIC PROTECTION		
8	Cathodic protection system in operating condition and functional?	☐Yes ☐No ☐NA	
9	Rectifier reading: Volts _____ Amps _____	☐Yes ☐No ☐NA	
	TANK EXTERNAL COATING		
10	Free of visible signs of paint failure?	☐Yes ☐No	
	TANK SHELL / HEADS		
11	Free of noticeable shell/head distortions, buckling, denting, or bulging?	☐Yes ☐No	
12	Free of visible signs of shell/head corrosion or cracking?	☐Yes ☐No	
	TANK MANWAYS, PIPING, AND EQUIPMENT		
13	Flanged connection bolts tight and fully engaged with no sign of wear or corrosion?	☐Yes ☐No ☐NA	
	TANK ROOF		
14	Free of standing water on roof?	☐Yes ☐No	
15	Free of visible signs of coating cracking, crazing, peeling, or blistering?	☐Yes ☐No	
16	Free of holes?	☐Yes ☐No	
	VENTING		
17	Normal and emergency vents free of obstructions?	☐Yes ☐No	
18	Normal vent on tanks storing gasoline equipped with pressure/vacuum vent cap?	☐Yes ☐No ☐NA	
19	Emergency vent in good working condition and functional, and tested as required by manufacturer?	☐Yes ☐No	

Any item marked "No" requires additional information to describe condition and date the condition is corrected.

	ITEM	STATUS	COMMENTS / DATE CORRECTED
		INSULATED TANKS	
20	Free of missing insulation?	☐Yes ☐No ☐NA	
21	Insulation free of noticeable areas of moisture?	☐Yes ☐No ☐NA	
22	Insulation free of mold?	☐Yes ☐No ☐NA	
23	Insulation free of visible signs of damage?	☐Yes ☐No ☐NA	
24	Insulation adequately protected from water intrusion?	☐Yes ☐No ☐NA	
		LEVEL AND OVERFILL PREVENTION EQUIPMENT	
25	Electronic or mechanical liquid level gauge tested for proper operation?	☐Yes ☐No ☐NA	
26	Electronic or mechanical liquid level gauge calibrated during the previous 12 months?	☐Yes ☐No ☐NA	
27	Is overfill prevention equipment in good working condition (overfill valve, audible alarm, etc.)?	☐Yes ☐No ☐NA	
28	Is tank ullage being determined and documented before filling the tank?	☐Yes ☐No ☐NA	
		ELECTRICAL EQUIPMENT	
29	Is tank/equipment grounding adequate and in good condition?	☐Yes ☐No	
30	Is electrical wiring for control boxes, lights, and other high voltage equipment in good condition?	☐Yes ☐No ☐NA	
		TANK / PIPING RELEASE DETECTION	
31	Is inventory control being performed and documented as required?	☐Yes ☐No ☐NA	
32	Is release detection being performed and documented on underground piping as required?	☐Yes ☐No ☐NA	

ADDITIONAL COMMENTS

INSPECTOR INFORMATION	
Printed Name:	Signature:

D
LIST OF TECHNOLOGIES

Table D-1
List of NDE Technologies for Tank Inspections

	Name of Technology	Tech. Category	Method Employed	Description	Tank Status for Inspection	Coverage	Damage Types Detected	Results	Applicable Materials	Capabilities/ Limitations
1	Ultrasonic Testing	Manual	Ultrasound (UT)	Application of standard UT technologies for thickness mapping	In- or Out-of-Service	Accessible metal surfaces	Near-side and far-side corrosion	Quantitative	Metallics	Area must be accessible by a human operator
2	Ultrasonic Phased Array	Manual	Ultrasound (UT)	Application of multi-element ultrasonic sensors for expedited corrosion mapping or weld inspection	In- or Out-of-Service	Accessible metal surfaces & welds	Near-side and far-side corrosion; Cracking.	Quantitative	Metallics	Area must be accessible by a human operator
3	Eddy Current Array	Manual	Eddy Current Testing (ECT)	Application of multi-element eddy current probes to detect surface-breaking cracks	In- or Out-of-Service	Accessible welds	Surface-breaking cracks	Qualitative to Quantitative	Metallics	Area must be accessible by a human operator
4	ACFM	Manual	Alternating Current Field Measurement	An electromagnetic technique that uses alternating currents induced in the test material	In- or Out-of-Service	Accessible welds	Surface-breaking & near-surface cracks.	Quantitative	Metallics	Area must be accessible by a human operator
5	Vacuum Box	Manual	Vacuum Box	Vacuum bubble leak testing of welds	In- or Out-of-Service	Welds	Through-wall cracking	Pass/Fail	Metallics	Crack must be through-wall to be detected; Typically applied by a human operator.
6	Helium (He) Mass Spectrometer Leak Testing	Manual	Tracer Gas Leak Testing	He is flushed inside system. Detection of He on outside indicates a leak. He can escape from very small openings & rise through soil, concrete & asphalt due to its small atomic size.	In- or Out-of-Service	Aboveground and underground storage tanks	Through-wall cracking and corrosion; Leaks at seals	Pass/Fail	Metallics and non-metallics	Can detect leaks from complex components such as valves, flanges, seals, etc.; Will not work on submerged leaks

Table D-1 (Continued)
List of NDE Technologies for Tank Inspections

	Name of Technology	Tech. Category	Method Employed	Description	Tank Status for Inspection	Coverage	Damage Types Detected	Results	Applicable Materials	Capabilities/ Limitations
7	Dye Tracer Testing	Manual	Dye Tracer Testing	Used to locate the source of a water leak. Water source is colored with a pigment or fluorescent dye. Exterior of structure is investigated for traces of the dye.	In-Service	Submerged regions of tanks	Through-wall cracking & corrosion; Leaks at seals	Pass/Fail	Metallics & non-metallics	Detect leaks from complex components (valves, flanges, seals, etc.). Not for buried components as dye must be visually detected. Only submerged components /areas will be tested
8	FirstMap Corrosion Mapping	Manual	Encoded AcoustoCam Ultrasound Technology	C-scan image is generated using unique ultrasonic techniques. Probe is encoded to generate images.	In- or Out-of-Service	Floor; Shell; Piping	Near-side & far-side corrosion	Quantitative	Metallics	Area must be accessible by a human operator
9	Infrared Inspection	Manual	Thermal Infrared Camera	Locate and document hotspots and regions where insulation is missing. Finds problems in steam systems such as degradation and blocking.	In- or Out-of-Service	Any component which can be visually inspected	Near-side & far-side corrosion	Qualitative	Metallics & non-metallics	Any component accessible with an infrared camera; Rapid, large area inspection potential; Detects product level
10	Short Range Guided Wave Testing (SR-GWT)	Manual	Ultrasonic Guided Wave	Ultrasonic guided waves launched from outside tank into tank floor, roof, support, etc. Waves reflected from pitting and corrosion are detected. Applied from inside for rapid, large-area screening.	In- or Out-of-Service	Tank roofs; Floors; Shells; Supports; Other difficult to access locations	Near-side & far-side corrosion; Cracking.	Qualitative to Quantitative	Metallics	Large-area screening technique; Inspection limited to several feet from sensor location; Potential to inspect inaccessible areas
11	FLOORMAP3D, FLOORMAPVS2I, MFL2000, and HANDSCAN	Manual	Magnetic Flux Leakage (MFL)	Various computerized MFL floor scanners	Out-of-Service	Floor	Near-side & far-side corrosion	Qualitative to Quantitative	Ferrous metallics	Only applicable to ferrous material

Table D-1 (Continued)
List of NDE Technologies for Tank Inspections

	Name of Technology	Tech. Category	Method Employed	Description	Tank Status for Inspection	Coverage	Damage Types Detected	Results	Applicable Materials	Capabilities/ Limitations
12	SLOFEC	Manual	Saturation Low Frequency Eddy Current Technology	Eddy current technology capable of detecting determining product-side and soil-side defects; Ability to penetrate through coatings and determine changes in coating thickness; Does not require follow-up UT	Out-of-Service	Floor	Near-side & far-side corrosion	Qualitative to Quantitative	Metallics	Provides quantitative information when properly calibrated; Can work through liners up to 0.300" thick
13	Radiography Testing	Manual	Radiography	X-ray and gamma ray to inspect very thick and thin metals of varying densities; Can also be used for welds; On-site film development performed	Out-of-Service	Variety of components	Near-side & far-side corrosion; Cracking	Qualitative	Metallics	Inspection area must be accessible from both sides; Requires radioactive source
14	Magnetic Flux Leakage Scanner	Robotic / Autono-mous	MFL	A steerable motorized corrosion detection instrument used in aboveground storage tanks to detect metal loss due to corrosion in tank floors	Out-of-Service	Floor	Near-side & far-side corrosion	Qualitative to Quantitative	Ferrous metallics	Only applicable to ferrous material.
15	Automated Ultrasonic Crawler	Robotic / Autono-mous	UT	Automated UT scanner which provides ultrasonic line scans	In- or Out-of-Service	Floor; Shell	Near-side & far-side corrosion	Quantitative	Metallics	Robot may require ferrous walls for magnetic attachment
16	OTIS® Robotic Tank Inspection	Robotic/ Autono-mous	UT	Robot follows a digital inspection grid, collects ≤ 200,000 ultrasonic scans with UT sensor array for computerized analysis; API 653 compliant, used with water & light/middle distillates with six in. or less of sludge, option for cleaning	In-Service	Floor	Near-side & far-side corrosion	Quantitative	Metallics	API 653 compliant; Capable of cleaning floor; Detects floor or shell settling; Fiberglass coating thickness measurement; Video of tank roof underside and vapor space structures

Table D-1 (Continued)
List of NDE Technologies for Tank Inspections

	Name of Technology	Tech. Category	Method Employed	Description	Tank Status for Inspection	Coverage	Damage Types Detected	Results	Applicable Materials	Capabilities/ Limitations
17	Inspector: Underwater In-Tank Assessor Robot	Robotic / Autono-mous	UT, ECT, Laser Profilometry	Inspector is a robotic platform & system, locates & maps tank bottom defects, ± 1/8 in. accuracy in water-filled/dry tanks ≤ 50 feet (15 m) in diam.; Inspector system is composed of robot, in-tank, hatch-mounted camera, & operator's console	In-Service	Floor; Welds	Near-side & far-side corrosion; Surface-breaking cracks	Qualitative to Quantitative	Metallics	360 degree video imaging; Overhead precision navigation system; 3D laser scanning; UT Corrosion Mapping; ECT Weld Inspection
18	Maverick	Robotic / Autono-mous	UT	Scans tank with UT array; Generates A-, B-, and C-scans	In-Service	Floor	Near-side & far-side corrosion	Quantitative	Metallics	A-scan data & B- & C-scan imaging on-site; API 653 certified
19	ARTIS	Robotic / Autono-mous	Visual, Laser Profilometry	Autonomous rail-guided tank inspection system with visual inspection with camera and laser scanner	In-Service	Unsubmerged regions; Tank floor if liquid is clear	Near-side corrosion	Quantitative	Metallics & non-metallics	Near-side surface profiling; Not capable of far-side corrosion detection of mapping; Surface must be clean
20	XR Spider	Robotic / Autono-mous	UT	Magnetically coupled robotic crawler carries UT transducer for corrosion mapping of walls/floors	In- or Out-of-Service	Shell; Floor	Near-side & far-side corrosion	Quantitative	Metallics	Robot may require ferrous walls for magnetic attachment
21	TriPod Tank and Vessel Scanner	Robotic / Autono-mous	Varied	Magnetically coupled tank-/vessel-oriented robotic platform with capability to deliver NDE technologies	In- or Out-of-Service	Shell; Floor	Dictated by method deployed	Dictated by method deployed	Ferrous Metallics for climbing	Robot may require ferrous walls for magnetic attachment

Table D-1 (Continued)
List of NDE Technologies for Tank Inspections

	Name of Technology	Tech. Category	Method Employed	Description	Tank Status for Inspection	Coverage	Damage Types Detected	Results	Applicable Materials	Capabilities/ Limitations
22	Guided Wave Monitoring of Tank Floors	Structural Health Monitoring	Ultrasonic Guided Wave	Ultrasonic guided waves generated from permanent sensors on tank exterior, used to create tomographic images of tank floor; Active monitoring system	In-Service	Floor	Near-side and far-side corrosion	Qualitative	Metallics	Long-term monitoring from tank exterior; In-service monitoring; Enable condition-based prioritization; Locates areas of damage growth relative to a baseline state
23	TankPAC	Structural Health Monitoring	Acoustic Emission (AE)	Acoustic emission passive monitoring system for tank floors, identifies areas of active corrosion by listening for noise generated by corrosion product	In-Service	Floor	Near-side & far-side corrosion; Leak Detection	Qualitative	Metallics	Long-term, in-service monitoring from exterior; Enables condition-based prioritization; Locate active corrosion & through-wall leaks
24	Acoustic Emission Leak Detection	Structural Health Monitoring	Acoustic Emission (AE)	Acoustic emission sensors used to identify location of leaks by listening for characteristic leak noise profile	In-Service	Submerged regions of tanks	Leak Detection	Pass/Fail to Qualitative	Metallics & non-metallics	Leak identification & basic location; May also detect non-leaking flaws; Tank must be relatively full or other pressure source must be applied

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