Harvey Consulting, LLC.

*Oil & Gas, Environmental, Regulatory Compliance, and Training*

| | |
|---|---|
| Linda Swiss | Austin Love |
| PWSRCAC | PWSRCAC |
| 3709 Spenard Road, Suite 100 | P.O. Box 3089 |
| Anchorage, AK 99503 | Valdez, AK 99686 |

May 23, 2015

Dear Ms. Swiss and Mr. Love,

Per your request, this report summarizes my review of Alyeska Pipeline Service Company's (APSC's) 2012 American Petroleum Institute Standard No. 653 (API 653) out-of-service internal and external inspection on Crude Oil Tank No. 14 (Tank 14), and available Cathodic Protection (CP) data for Tank 14.

This report summarizes the findings of the 184 page inspection report produced by APSC's API 653 inspector, and compares the inspector's findings to prior in 1998 (out-of-service), 2004 (in-service, external only), and 2009 (in-service, external only). This report also examines whether the cathodic protection system installed under the new tank floor (in 1998) has remained operational and protective during the period of 1999-2014.

Overall, I found the 2012 Tank 14 inspection report to be very thorough, well documented, and technically supported. The quality of the Tank 14 API 653 inspection report was a substantial improvement over the crude oil tank inspection reports previously provided to PWSRCAC. Tank 14's 2012 inspection report included: tables showing the actual measurements collected during the inspection; tables showing the inspector's corrosion loss computations; photographs of damage and repairs; a list of recommended repairs, along with evidence that the repairs were made prior to returning Tank 14 to service; and, inspection data for the roof support columns, sumps, fire foam system piping, foundation and other appurtenances (nozzles and valves). The cathodic protection system remained operational from 1999 to May 2005 and November 2005 to 2014, with a few outages during periods of maintenance, inspections, and repairs. From May 2005 to November 2005, the cathodic protection system was not operating due to a damaged CP conduit.

A list of findings is provided in Section 2, and a list of recommendations is provided in Section 15 of this report. Please give me a call at (907) 694-7994 if you have any questions on this report.

Sincerely,

*Susan L Harvey*

Susan L. Harvey

# Contents

## 1. Introduction

In 2012, Alyeska Pipeline Service Company (APSC) completed an American Petroleum Institute Standard No. 653 (API 653) out-of-service inspection (internal and external inspection) on Crude Oil Tank No. 14 (Tank 14) to meet regulatory requirements. API 653 inspection methods are used to determine the suitability of a tank structure for continued service, to identify any necessary repairs, and to make sure repairs are completed before the tank is returned to service. In addition to the API 653 Standard, APSC's Alyeska Pipeline Master Specification T-500, Tank Corrosion Investigation procedures, and standards were used.

The purpose of this report is to review APSC's 2012 API 653 out-of-service (internal and external) inspection on Tank 14, and available Cathodic Protection (CP) data for Tank 14. This report summarizes the findings of the 184 page inspection report produced by APSC's API 653 inspector and examines whether the cathodic protection system installed under the new tank floor (installed in 1998) has remained operational and protective during the period of 1998-2014. More specifically, PWSRCAC requested that Harvey Consulting, LLC review the two reports provided by APSC for the 2012 Tank 14 API 653 inspection.

(1) APSC's Engineering Summary Report, prepared by Hally Cooper, APSC Project Engineer, February 2013 summarizing the August 2012 inspection; and,

(2) The API 653 inspector's Report prepared by Thomas Hazlett, Team Peak Alaska, for APSC on December 15, 2012, summarizing the August 2012 inspection.

Additionally, Harvey Consulting, LLC compared the 2012 inspection results to the results of four prior inspections completed on Tank 14 [1990 (out-of-service), 1998 (out-of-service), 2004 (in-service, external only), and 2009 (in-service, external only)] to evaluate corrosion trends, and improvements in report content and methods. The quality of the 2012 inspection report was a substantial improvement over the crude oil tank inspection reports previously provided to PWSRCAC.

A list of findings is provided in Section 2, and a list of recommendations is provided in Section 15 of this report.

## 2. Executive Summary of Tank 14 Inspection Findings

**2.1** A new tank floor was installed in 1998. A maximum floor plate corrosion loss of 14% was measured during the 2012 inspection (soil-side corrosion). Assuming this corrosion rate continues on a linear trend, the 2012 inspector computed a remaining service life of 47.9 years for the tank floor.

**2.2** Twenty eight (28) annular ring plates had top-side damage caused by air carbon arc gouging during the 1998 floor replacement. The inspector reported the removal of seven (7) floor plates in 1998 resulted in "significant" damage that exceeded 0.100" deep. Gouges greater than 0.100" deep were weld-repaired and vacuum box tested. Less significant damage (less than 0.100" deep) occurred on the other 21 plates; that damage was ground out to remove acute edges to avoid compromise the new floor coating. The inspector also found four spots of mechanical damage that were weld repaired. The record is unclear on why this damage was not repaired in 1998 before the tank was returned to service.

**2.3** All annular ring plate measurements taken in 2012 exceeded the minimum required plate thickness of 0.580”; however, the thinnest 2012 inspection measurement (0.668”) was higher than the prior 1998 inspection measurement of 0.595” remaining thickness (isolated corrosion pitting). Based on the minimum remaining thickness measurement (0.595”) a remaining service life of 22 years is estimated.

**2.4** Tank 14’s shell has very little corrosion. The highest amount of corrosion (7%) was measured at the top of the tank near the roof. The remaining service life for the tank is expected to exceed 20 years. External API 653 (in-service) inspections are completed every 5 years. External inspections provide additional data to monitor the tank shell’s condition prior to the next out-of-service API 653 inspection (Year 2032).

**2.5** Very little of the roof was inspected in 2012. Tank 14’s roof area is larger than one acre. Less than 0.6% of the roof was inspected, and the inspection was limited to five roof plates. The inspector reported a minimum roof plate thickness of 0.299” which equates to a 20% corrosion loss. A thinner roof plate measurement was collected in 2009 (0.290”), equating to a 23% corrosion loss.

**2.6** Tank 14’s 61 internal roof support columns had no significant corrosion.

**2.7** The sump, and 36” suction fill line did not have significant corrosion.

**2.8** Tank 14 has a concrete ring wall foundation. The inspector found the seal around the bottom of the tank had “*mostly failed*” with vegetation and root systems prevalent in 2012. The seal is used to prevent water from running beneath the tank. Vegetation and root systems can damage the liner and foundation.

**2.9** The 20” fire foam system piping network installed inside the tank bottom showed internal corrosion. The most significant corrosion was found 70’10” downstream from the internal flange face connection (42% wall loss). No repairs or replacements were made. No information was provided on the minimum wall thickness required for continued safe operation.

**2.10** The 2012 inspector recommended Tank 14’s next API 653 out-of-service inspection to be completed in 2032, 20 years after the 2012 inspection, based on the estimated remaining service life of the tank floor and annular ring.

**2.11** Cathodic protection system records for 1999 to 2014 were provided by APSC. Cathodic protection system data for those periods showed the system was operational and met National Association of Corrosion Engineers (NACE) Recommended Practice (RP-0193-93) for all points measured (except May 2005 to November 2005 when cathodic protection system was not operating due to a damaged CP conduit.

**2.12** Cathodic protection system data for 2012 was not available. Tank 14 was inspected in 2012. The cathodic protection system was turned off during the inspection. It is unclear why cathodic protection system testing was not completed later in the summer or early fall of 2012 when the API 653 tank inspection was complete, and the system resumed operation.

**2.13** APSC substantially reduced the number of cathodic protection system test points it measured under Tank 14 from 54 test points in 1999-2008 to only 10 test points in 2009 to 2011 and 2013. In 2010, PWSRCAC raised concern about the reduced number of test points. In 2014, APSC resumed the higher testing frequency to 50 test points.

## 3. Tank 14 Construction and Inspection History

Tank 14 is a crude oil storage tank at the Valdez Marine Terminal (VMT). Tank 14 was built on site at the VMT in 1976. As of this report (Year 2015), Tank 14 is 39 years old. Tank 14 is a carbon steel tank with a concrete ring wall and a fixed welded cone roof, and welded shell.

Tank 14 is 62’4” tall, and 250’ in diameter. If filled full, Tank 14 can hold 547,525 barrels. However, APSC limits the fill level to 58’6”. Tank 14’s maximum storage capacity at the 58’6” fill level is 510,000 barrels.[1]

The first out-of-service (internal and external) inspection was completed after 14 years of use (1990). The inspector reported “very little significant corrosion” in 1990.[2]

The second out-of-service tank inspection was completed in 1998. In 1998, the original tank floor bottom was replaced due to soil side corrosion. In 1998, the original tank floor was replaced and coated with Devoe Bar Rust 236. The shell and columns were coated three feet up from the floor. A foot of clean sand was placed under the new tank floor and a grid anode ribbon cathodic protection system was installed to protect the tank floor from the corrosive effects of the soil. Tank 14 has an impressed current Cathodic Protection (CP) system that uses Mixed Metal Oxide (MMO) ribbon anodes in a grid and perimeter ring orientation under the tank floor. The anodes are buried approximately 9” below the tank on 2’6” center spacing.[3] Cathodic protection is applied to the steel tank by providing small amounts of direct electrical current to the anodes buried below the tank to blanket the tank bottom with a hydrogen ion film (polarization) to interrupt the corrosion process.[4]

API 653 requires a new tank floor to be inspected within 10 years of installation to verify the corrosion rate; this inspection was due in 2008. APSC requested a four year extension of time to complete the next API 653 out-of-service inspection in 2012.[5] On January 24, 2008, ADEC denied APSC’s request to extend Tank 14’s internal inspection past 10 years, stating: *“The Department does not agree that an internal inspection beyond a ten year interval for either TK 13 or TK 14 is in keeping with our regulations found in 18 AAC 75.065(a).”*[6] APSC responded with additional data on March 5, 2008.[7] On April 25, 2008, ADEC approved a four year deferral; allowing the next internal inspection to be completed in 2012.[8] PWSRCAC opposed this inspection interval extension.[9]

---

[1] 2014 Valdez Marine Terminal C-Plan, Part 3, Table 3-1, Page 3-2.

[2] CTI Tank 14 Inspection Report prepared for APSC, November 16, 1990.

[3] 2002 TAPS Valdez Marine Terminal Cathodic Protection Survey, WO# 32000354-01, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., December 30, 2002.

[4] Project L019, 1999 Annual Cathodic Protection Survey of the Valdez Marine Terminal and SERVS Facility, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., January 2000.

[5] APSC letter to ADEC (Alaska Department of Environmental Conservation), VMT Crude Oil Storage Tanks 13 and 14 Internal Inspection Deferral, December 18, 2007.

[6] ADEC letter to APSC, APSC Letter No. 13980, VMT Crude Oil Storage Tanks 13 and 14 Internal Inspection Deferral, January 24, 2008.

[7] APSC letter to ADEC, Request for Technical Review/Waiver Request for VMT Crude Oil Storage Tanks 13 and 14, March 5, 2008.

[8] ADEC letter to APSC, APSC Letter No. 15085, VMT Crude Oil Storage Tanks 13 and 14 Internal Inspection Waiver, April 25, 2008.

[9] PWSRCAC opposed the inspection delay for the following reasons: the API 653 requires a floor bottom corrosion rate to be established after 10 years in use (meaning the new tank floor installed in 1998 required an inspection in 2008); in the 1998 inspection three annular plates had corrosion that came close to APSC’s design criteria and a linear extrapolation of this data would exceed the design criteria in 10 years; roof corrosion was evident; sediment and sludge had been found in Tank 14 over the

In-service (external) inspections were completed in 2004 and 2009.

The 2012 inspection is the third API 653 out-of-service inspection for Tank 14. The fourth out-of-service inspection is planned for year 2032, when Tank 14 will be 56 years old. APSC plans to complete in-service (external) inspections every five years.

## 4. Floor Inspection

**4.1 Design Information** Tank 14's floor, installed in 1998, was made of 215 welded steel plates (0.25" nominal design). The tank floor was coated with Devoe Bar Rust 236 approximately 0.012" – 0.016" thick.

**4.2 2012 Inspection Method**: Tank 14's floor was inspected using a Magnetic Flux Leakage (MFL) tool. Manual Ultrasonic Testing (MUT) was also used to verify the MFL tool indications during the initial inspection and to inspect any areas that were not accessible to the MFL scanner. A visual inspection of the shell-to-floor weld was completed.[10]

**4.3 2012 Inspection Results & Repairs:** The 14-year-old internal coating system (installed in 1998) was found in good condition. A few minor chips exposed the metal substrate.[11]

Minor to moderate soil-side corrosion was found on the tank floor. Fourteen (14) floor plates were identified by using the Magnetic Flux Leakage tool for follow-up Manual Ultrasonic Testing.[12] Two areas with the lowest remaining thickness were due to a carbon arc gouge and a grinding gouge.[13] These floor plates were repaired with weld build-up. Surface anomalies on the other plates were ground flush or gradually feathered with the adjacent metal base. The sump wear plates were weld repaired.

Floor Plate 111 had the lowest remaining thickness (0.230").[14] The highest corrosion found on floor plate Floor Plate 111 was attributed to a "possible hammer indentation." The inspector computed a corrosion loss of 14% corrosion loss since the new tank floor was installed in 1998, based on the actual floor plate thickness of 0.268" (installed in 1998).[15]

The detailed floor inspection data sheets showed thinner floor plate measurements of 0.189" (Floor Plate 101A) and 0.192" (Floor Plate 167A).[16] These floor plates were approximately 28-29% thinner than the rest of the tank floor due to mechanical damage caused during the 1998 tank installation. These floor plates were repaired in 2012. The API 653 standard does not include floor plate measurements in the remaining service life calculation if the plate is repaired to original

---

foam distribution system located above the tank floor at the bottom of the tank (sediment build-up over this system can cause foam system blockages, potentially impacting foam distribution and concentration); and, because routine inspections are a critical part of an oil spill prevention program for large tanks storing crude oil in a critically sensitive habitat area.

[10] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 8.

[11] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 9.

[12] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 20.

[13] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 10.

[14] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 11.

[15] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 11.

[16] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 84-85.

thickness before return to service. Therefore, the thinnest floor plate used in the remaining service calculation is 0.230” thick (Floor Plate 111).

**4.4 Remaining Service Life Calculation Based on 2012 Inspection Results**: The actual floor plate thickness of the tank floor was 0.268” in 1998. The maximum corrosion depth found during the 2012 inspection was 0.038”. Therefore, the lowest remaining floor thickness was computed to be 0.230”. Using the maximum floor corrosion found since 1998 (0.038”) and the time interval between the date the new floor was installed (1998) and the inspection date (2012) of 14 years, a corrosion rate of 0.00271” per year was computed. API 653 recommends the minimum tank floor plate thickness for a tank bottom with no means for bottom leak detection of a bottom leak should be at least 0.100” thick.[17] Using the lowest remaining floor thickness measured during the 2012 inspection, in the area with the highest corrosion (0.230”) and ensuring a 0.100” remaining floor thickness by the next inspection, a corrosion allowance of 0.130” was computed.

The 2012 inspector assumed the corrosion rate exhibited from 1998 to 2012 (0.00271” per year) would remain linear, with no future acceleration.[18] Based on this assumption, the API 653 inspector computed a remaining service life of 47.9 years[19]

**4.5 Floor Summary**: A summary of the floor design and inspection data is shown in the table below.

| Tank 14 Floor Design and Inspection Data | Inspection Year | Measured Thickness |
|---|---|---|
| New floor installed | 1998 | 0.268” |
| MFE and MUT Inspection Data | 2012 | 0.230” |
| Minimum required thickness for a tank with no leak detection below the tank floor (API 653) | | 0.100” |

## 5. Annular Ring Plate Inspection

**5.1 Design Information**: The annular ring (that connects the tank floor to the tank shell) is made up of 0.8125” thick (13/16”) welded steel plates, that are 6’ wide.[20] The tank floor and exposed section of the annular ring was coated with Devoe Bar Rust 236 approximately 0.012” – 0.016” thick.

API 653 recommends the minimum annular ring thickness for tanks, like Tank 14 that use thickened annular plates for seismic considerations, be established by a seismic engineering evaluation, using the actual thickness of the existing annular plate.[21] Both the 2012 inspector’s report, and the 2013 APSC engineering report of the 2012 inspection, reference an Engineering Study completed by Aiken Engineering that computed the minimum annular ring plate thickness needed to support the crude oil storage tanks during the a seismic event in Valdez. Neither the 2012 inspector’s report, nor the 2013 APSC engineering report of the 2012 inspection specifies the magnitude of the maximum seismic event used in the study. The Aiken Engineering study recommended APSC engineers use a 0.580” minimum thickness, excluding deeper corrosion

[17] API 653 Standard, Chapter 6.

[18] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14’s August 2012 inspection, Page 9.

[19] 47.9 years= (0.130” corrosion allowance/ 0.00271” corrosion rate per year).

[20] Hally Cooper (APSC), Engineering Corrosion Report 54-TK-14, February 2013, Page 3.

[21] API 653 Standard, Chapter 4, Minimum Thickness for Annular Plate Ring.

attributed to isolated pitting. It is important to obtain a copy of the Aiken Engineering for review by PWSRCAC's seismic expert to ensure the 0.580" is based on conservative assumptions.

**5.2** **2012 Inspection Method**: Tank 14's annular ring plates were inspected using an Electromagnetic Acoustic Transmission (EMAT) system and Manual Ultrasonic Testing (MUT).
The critical zone of the annular ring (the 3" section of annular plate adjacent to the tank shell, measured from the inside edge of the shell measured radially inward) that is inaccessible to EMAT was inspected using MUT. The annular plate-to-shell weld was visually inspected.[22]

**5.3** **2012 Inspection Results & Repairs.** The inspection measured minor to moderate soil-side corrosion pitting of the annular ring plates including the 3" critical zone of the annular ring plates.[23] The inspector computed corrosion loss of up to 14% maximum (Annular Plate A12) at a remaining thickness of 0.668" compared to the adjacent base metal thickness of 0.78" (measured in 2012) for a plate loss of 0.112".[24] The maximum corrosion loss should have been computed from the original 0.8125" plate thickness (18%).[25] The inspector concluded this was an isolated, soil-side corrosion pit.[26]

Twenty eight (28) annular ring plates had top-side damage caused by air carbon arc gouging during the 1998 floor replacement. The removal of floor plates in 1998 resulted in "significant" damage to Plates A05, A11, A18, A19, A22, A23, and A28 that exceeded 0.100" deep. Gouges greater than 0.100" deep were weld-repaired and vacuum box tested. Less significant damage (less than 0.100" deep) occurred on the other 21 plates; damage was ground out to remove acute edges so those areas of damage will not compromise the new floor coating. The inspector also found four spots of mechanical damage that were weld repaired.[27]

**5.4** **Comparison to Prior Inspection Results**: In 1990, Automated Ultrasonic Testing (AUT) was used to scan the annular ring plates for corrosion loss. Two 16" AUT test bands were run, testing all but a 4" band of the annular ring. The 1990 inspector concluded, "*no significant corrosion was found in the annular ring*."

In 1998, Manual Ultrasonic Testing (MUT) was used to examine 100% of the exposed surface of the annular plate ring. In addition, thirty 12" x 12" AUT scans were completed on randomly-selected annular ring plates. The 1998 MUT testing showed corrosion on the annular plates, with the most significant corrosion on plates A01, A07, and A21. These areas were not repaired because they were above APSC's design standard of 0.58" for the annular plate ring critical thickness. APSC's engineers described these areas as "*isolated pitting*" of the plates. Remaining minimum thicknesses for Plates A01, A07, and A21 was measured at 0.71", 0.595", and 0.660", respectively.

The 2012 ultrasound inspection measured thicknesses for Plates A01, A07, and A21 exceeding the 1998 inspection results.[28]

[22] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 8.

[23] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 9.

[24] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 11.

[25] (0.8125-0.668)/0.8125*100= 17.8%

[26] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 10.

[27] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 9.

[28] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 24, 95, 98, and 100.

| Tank 14 Annular Ring Inspection Data (remaining thickness) | 1998 Inspection | 2012 Inspection | Difference |
|---|---|---|---|
| Plate A01 | 0.710” | 0.785” | +0.075” |
| Plate A07 | 0.595” | 0.775” | +0.180” |
| Plate A21 | 0.660” | 0.761” | +0.101” |

The 2012 inspection report did not explain why the 1998 and 2012 measurements differed. API 653 Section 6 requires an inspection history to be maintained on the tank, including corrosion rate and inspection interval calculations. The prior internal inspection in 1998 measured annular ring corrosion that exceeded the measurements reported in 2012.[29] The prior annular ring inspection data was not addressed in the 2012 inspector's report and compared with the data collected in 2012. It is possible the 2012 inspector found the 2012 measurements to be more accurate (using EMAT followed by MUT instead of Automated Ultrasonic Testing (AUT) previously used), discounting the data collected in 1998. However, it would have been useful for the 2012 inspection report to acknowledge prior measurements of the most significant corrosion found in prior inspections, explain what work was done to more thoroughly investigate those areas, and explain why the new, 2012 thicker measurements were more accurate, invalidating the 1998 data set (if that was the case).

**5.5** **Remaining Service Life Calculation**: Using the maximum annular ring plate corrosion found since 1976 (0.112”, reported as an isolated, soil-side corrosion pit on Annular Plate A12) and the time interval between the date the ring plates were installed (1976) and the inspection date (2012) of 36 years, the inspector computed a corrosion rate of 0.00311” per year. Using the lowest remaining annular ring plate thickness during the 2012 inspection, in the area with the highest corrosion (0.668”) and ensuring a 0.580” remaining plate thickness by the next inspection, a corrosion allowance of 0.088” was computed. The 2012 inspector assumed that the corrosion rate exhibited from 1976 to 2012 (0.00311” per year) would remain linear in the future.[30] Based on this assumption, the inspector computed a remaining service life of 28.3 years (0.088” corrosion allowance/ 0.00311” corrosion rate per year).

The inspector's calculations for a remaining service life of 28.3 years assumed the original annular plate thickness in 1976 was 0.780” thick; it was actually 0.8125” thick. Revising the calculation using the correct original annular plate thickness in 1976, results in a remaining service life of 22 years.[31]

**5.6** If the 1998 corrosion data (0.595” remaining plate thickness) was used to compute the remaining service life it would be substantially shorter. Therefore, it is important for APSC to confirm the 1998 data was invalidated by the new data collected in 2012. Otherwise, APSC should use a shorter more conservative remaining service life.

The 2013 APSC engineering report, of the 2012 Tank 14 inspection, computed a remaining life of 141 years for the annular plate using a minimum thickness of 0.100” allowed by API 653, in areas

[29] TK-14, Internal Inspection Report Excerpts from the 1998 inspection provided by APSC to ADEC as part of its request to defer the 2008 out-of-service inspection date.

[30] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 9.

[31] 0.8125” (thickness in 1976) – 0.6680” (remaining thickness in 2012) = 0.1445” (corrosion depth).
0.1445” (corrosion depth)/36 years since tank was built = 0.0040” per year (maximum corrosion rate)
0.668” -0.580” (minimum required thickness from APSC Seismic Study) = 0.088” (corrosion allowance)
0.088”/0.0040” per year = 22 years

that are not seismically active.[32] This estimate did not take into consideration the fact that the API Standard requires a seismic engineering assessment to establish the minimum annular plate thickness in seismically prone areas. The 0.100" minimum default does not apply in seismically active areas. The 2013 APSC engineering report was silent on the reason why the 2012 inspection data measured thicker annular plates for Plates A01, A07, and A21 than the measurements taken in 1998.

**5.7 Annular Ring Plate Summary**: A summary of the annular ring plate design and inspection data is shown in the table below.

| Tank 14 Annular Ring Plate Design and Inspection Data | Inspection Year | Measured Thickness |
|---|---|---|
| Annular Plate Installed | 1976 | 0.8125" |
| MUT and AUT Inspection Data (isolated pit) Plate A07 | 1998 | **0.5950"** |
| EMAT and MUT Inspection Data (isolated pit) Plate A12 | 2012 | 0.6680" |
| Minimum required thickness for a tank operating in a seismically active zone per APSC Spec. X058-T-500 (API 653) | | 0.5800" |

## 6. Shell Inspection

**6.1 Design Information**: The original design criteria for Tank 14 included a tank shell thickness that varies with height. The tank was constructed with eight tank shell courses: the 1st course at the bottom, and the 8th course at the top. The original thickness of the 1st course was 1.121" thick, 2nd course (0.969"), 3rd course (0.832"), 4th course (0.699"), 5th course (0.569"), and 6th to 8th courses (0.5"). All courses included a 0.125" corrosion allowance in the design.[33]

In 1998, the tank shell was coated with Devoe Bar Rust 236 approximately 0.012" – 0.016" thick three feet up from the floor. The water draw valve was also coated.

**6.2 2012 Inspection Method**: A limited area of Tank 14's 8th shell course (6.6 $ft^2$) was scanned using an Automated Ultrasonic Testing system and Manual Ultrasonic Testing.[34] Manual Ultrasonic Testing was used to inspect the 2nd through 7th shell courses and the shell nozzles. There were nine (9) readings on each plate of the first shell course; three (3) readings on one plate of the 2nd to 7th shell course; four (4) readings on each shell nozzle and each roof nozzle.[35] Three measurements were made on each shell course (2nd -8th); one within 1.5" of the top section of each course, one in the middle, and one within the bottom 1.5" of each course.

[32] Hally Cooper (APSC) Engineering Corrosion Report: 54-TK-14, February 2013, Page 4.

[33] The API 653 standard, *Minimum Thickness Calculation for Welded Tank Shell,* does not apply to tank diameters in excess of 200.' Tank 14's diameter is 250'. Therefore, the original design criteria for this tank must be used. API 653, *Tank Shell Evaluation*, requires corrosion greater than the original design allowance to be evaluated by an engineer to determine suitability for continued service if the corrosion might adversely affect the performance or structural integrity of the tank shell. API 653 requires "*any thinning of the tank shell below minimum required wall thickness due to corrosion or other wastage may be evaluated to determine the adequacy for continued service by employing the design by analysis methods defined in Section VIII, Division 2, Appendix 4 of the ASME Code*."

[34] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 113-114.

[35] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 106-113.

**6.3 2012 Inspection Results & Repairs**: The inspector measured no corrosion on the 2nd through 6th shell courses, 1% corrosion on the 1st and 7th shell courses, 7% corrosion on the 8th shell course.[36] The inspector concluded there was no significant corrosion activity on the shell nozzles.[37]

**6.4 Comparison to Prior Inspection Results**: Prior inspections measured minimum remaining shell thickness in 1998 (out-of-service), 2004 (in-service), and 2009 (in-service).

The 1998 internal inspection obtained ultrasonic measurements at four quadrants around the 1st course of the tank shell. Ultrasonic inspection of the 2nd-8th courses was taken from the tank staircase. Thickness measurements of the 2nd through 7th courses exceeded the original design nominal thickness. Minor corrosion was found on the 1st and 8th course.

The 2004 external inspection obtained 36 ultrasonic measurements on the 1st tank course. Thirty-five (35) measurements exceeded the original design nominal thickness of 1.12". Only one measurement was 1.11" thick. One ultrasonic measurement was taken on each of the 2nd through 8th tank courses. Measurements for the 2nd, 3rd, 4th, 6th and 7th tank courses exceeded the original design nominal thickness. The 5th and 8th course measurements were only slightly below the original design thickness (0.008" and 0.005" corrosion loss respectively).

In 2009, thirty-six (36) measurements on the 1st tank course exceeded the original design nominal thickness of 1.12". Data were not collected[38] on the 2nd, 3rd, and 4th courses because the tank stairway was blocked off due to snow load damage, and access was not permitted due to safety concerns. Data on the 5th through 8th course showed no significant corrosion.

The data collected in 2012 was generally consistent with the prior data collected, showing minor to no corrosion on most of the shell courses. A summary table of the prior inspections is shown on the following page.

**6.5 Remaining Service Life Calculation**: The API 653 Standard "next inspection interval computation" does not take into account the condition of the tank shell. Therefore, the API 653 inspector's 2012 tank inspection report only computes the remaining service life of the tank floor and annular ring. Based on those computations, the inspector makes a recommendation for the date of the next inspection interval. API 653 caps the length between out-of-service inspections at 20 years. In the case of the 2012 inspection, the inspector recommended the next inspection interval to be 20 years (2032).

However API 653 does recommend that in addition to completing the standard "next inspection interval computation" (based solely on the remaining floor and annular plate thickness), that the inspector also consider several other factors when setting the tank inspection interval, such as: "*(a) the nature of product stored, (b) The results of visual maintenance checks, (c) Corrosion*

[36] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 106-114.

[37] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 11, and 118-119.

[38] The 2009 Tank 14 report notes that APSC Tank Engineer Hally Cooper issued a "2009 External Inspection UT Exemption" where UT readings for tank shell courses 2, 3, and 4 were deferred due to "inaccessibility." There was no information in the report about how long the UT measurements will be deferred or any indication that ADEC had been consulted about the inability to obtain these inspection readings. The lack of UT data obtained on Tank 14 Shell Courses 2-4 was raised to Hally Cooper (APSC Tank Engineer) at the December 2010 VMT C-Plan Coordination Group Meeting. Ms. Cooper explained that APSC did not intend to secure the additional UT data, and would not obtain UT Shell data until the next internal inspection scheduled for 2012. APSC relies on API 653, section 6.3.3.2 to defer the shell UT data, because API allows a 15-year interval for UT data if the shell corrosion rate is known.

*allowances and corrosion rates, (d) corrosion prevention systems, (e) conditions at previous inspections, (f) the methods and materials of construction and repair, (g) the location of the tanks, such as those in isolated or high risk areas, (h) The potential risk of air or water pollution, (i) leak detection systems, (j) change in operating mode, (k) jurisdictional requirements, (l) changes in service (including changes in water bottoms), (m) the existence of a double bottom or a release prevention barrier.*

Therefore, is prudent to also consider the condition of the tank shell and roof, especially for tanks operating vapor recovery systems, located in a seismically active area, and in an environment of heavy snow/ice loading.

Based on the data collected in the 1998, 2004, 2009, and 2012 inspections, the remaining service life of the shell is estimated to be well beyond 20 years. Because Tank 14 operates a vapor recovery system, and corrosive vapors may exist toward the top of the tank, the corrosion rate may accelerate in future years. External API 653 inspections are completed on Tank 14 every five years. External tank inspections provide additional, more frequent measurements to monitor the tank shell condition.

In the past, three readings have been taken on each shell course (at different heights on one shell plate). This is a very low number of measurements for a tank that is 250’ in diameter. As the tank ages, it would be beneficial to consider collecting additional measurement locations on each shell course during the 5-Year API 653 external inspections (especially those showing increasing corrosion), particularly for tanks that will not receive their next out-of-service inspection for 20 years. This approach would provide additional data and improve confidence in the statistical significance of the data set.

Tank 14, Valdez Marine Terminal, Crude Oil Storage Tank

| Course No. | Design Thickness (inches) | Corrosion Allowance (inches) | Minimum Allowable Thickness (inches) | 1998 Internal Inspection, Lowest Remaining Thickness (inches) | 2004 External Inspection, Lowest Remaining Thickness (inches) | 2009 External Inspection, Lowest Remaining Thickness (inches) | 2012 Internal Inspection, Lowest Remaining Thickness (inches) | Corrosion Loss (%) since 1976** | Corrosion Loss (mpy) since 1976** | Remaining Service Life*** (years) |
|---|---|---|---|---|---|---|---|---|---|---|
| 8 | 0.500 | 0.125 | 0.375 | 0.480 | 0.495 | 0.490 | 0.463 | 7% | 0.0003 | >20 |
| 7 | 0.500 | 0.125 | 0.375 | > 0.500 | > 0.500 | 0.499 | 0.493 | 1% | 0.0002 | >20 |
| 6 | 0.500 | 0.125 | 0.375 | > 0.500 | > 0.500 | > 0.500 | 0.500 | 0% | 0.0000 | >20 |
| 5 | 0.569 | 0.125 | 0.444 | > 0.569 | 0.561 | 0.569 | > 0.569 | 0% | 0.0000 | >20 |
| 4 | 0.699 | 0.125 | 0.574 | > 0.699 | > 0.699 | * | > 0.699 | 0% | 0.0000 | >20 |
| 3 | 0.832 | 0.125 | 0.707 | > 0.832 | > 0.832 | * | > 0.832 | 0% | 0.0000 | >20 |
| 2 | 0.969 | 0.125 | 0.844 | > 0.969 | > 0.969 | * | 0.968 | 0% | 0.0000 | >20 |
| 1 | 1.121 | 0.125 | 0.996 | 1.140 | 1.110 | 1.120 | 1.109 | 1% | 0.0003 | >20 |

*Bottom stairway damaged by falling snow from prior winter. Inspector reported "stairs are currently condemned and access not permitted at this time."

**Corrosion loss was computed using the thinnest shell plate measurement since 1976.

***Remaining service life was estimated using the highest corrosion rate for each course.

# 7. Roof Inspection

**7.1 Design Information**: Tank 14's roof was originally made of 0.375" thick, welded steel plates, placed over structural steel rafters. Tank 14 is 250' in diameter, with a cone shape roof made of over 49,000 ft$^2$ of welded steel plates.[39] The roof area is over an acre in size.

There are two standards to consider when evaluating whether to repair or replace a tank roof: (1) the original design criteria that takes into account heavy snow loads, and (2) the substantially less conservative minimum roof thickness allowed by API 653 standard. The roof plates were originally designed at 0.375" thick, including a 0.125" corrosion allowance. Roof thicknesses measured at or above 0.250" exceed the original design tolerance. The API 653 Standard requires repair or replacement of roof plates with any holes through the roof plate or corrosion to an average thickness of less than 0.090" in any 100 inch squared (in$^2$) area.

Tank 14 has vapor control installed. Roof integrity is important for proper function and safety of this system. The roof was designed to hold the Valdez Alaska snow load. The API 653 standard (of 0.090" in any 100 inch squared (in$^2$) area. ) does not take into account Tank 14's snow loading design requirement or vapor recovery system operation requirements. For this reason, APSC's design thickness of 0.375", with a 0.125" corrosion tolerance, requiring the minimum roof plate thickness to be 0.250" thick or greater should be used. The 0.250" minimum threshold takes into account both the need for a sealed roof with no through holes and the need for a strong roof capable of supporting snow, provided snow removal is done on a periodic basis.

**7.2 2012 Inspection Method**: A limited area of Tank 14's roof was inspected (268.7 square feet (ft$^2$))[40] using the Automated Ultrasonic Testing (AUT) system. An inspection covering 268.7 ft$^2$ equates to only 0.6% of the roof. Twenty three (23) measurements were made on five (5) roof plates. Seven (7) concentrated on a single roof plate (Roof Plate 115); six (6) measurements were made on Roof Plates 113 and 114, and two (2) measurements were made on Roof Plates 112 and 160.[41]

Ultrasound inspection was also completed of the roof inspection openings, gauge thief hatch, 24" manways, 12" pressure vac vents, 10" inspecting openings, 16" vapor inlet, 30" vapor outlet.[42]

**7.3 2012 Inspection Results & Repairs**: The inspector measured generalized wall thinning of the roof. The inspector's summary report lists the highest roof corrosion rate at 10%.[43] The inspector's corrosion calculation compared the thinnest area on the roof plate (area with the most corrosion) to the thickness of the adjacent base metal. The corrosion calculation should have compared the thinnest area measured on the roof plate to the original roof plate thickness. The thinnest roof plate measurement was 0.299". The original roof plate thickness was 0.375" which makes the corrosion loss 20% not 10%. The inspector measured a maximum wall loss of 7% on the 30" vapor recovery

---

[39] 49,000 sq. ft. is based on a simple calculation of the area would be covered by a flat roof on top of a 250' diameter tank. Tank 14 has a conical shape roof, which increases this area above the 49,000 sq. ft. amount. The 49,000 sq. ft. estimate was used as a conservative estimate.

[40] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 139-174.

[41] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 37 and 38.

[42] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 176-179.

[43] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 38.

vent (V2).[44]

**7.4 Comparison to Prior Inspection Results**: The 1998 internal roof inspection showed thinning of a number of roof plates around the vapor recovery nozzle (Roof Plate 116) and the pressure relief vent (Roof Plate 26). Measurements were made by ultrasonic technique. The thinnest roof plate measurement recorded was 0.319" (Roof Plate 111). The inspector's report states "visual inspection of the bottom side of the roof did reveal large areas of the surface corrosion," but no areas were below the critical thickness for roof integrity according to API standards. A topside roof visual inspection was completed. The inspector determined repair was not warranted. Roof Plate 111 was measured in 2012 with a remaining thickness of 0.335" (thicker than the 1998 measurement).

The 2004 and 2009 external roof inspections collected 52 roof thickness measurements by ultrasonic technique, by sampling 13 points along the roof in the north, east, south, and west compass directions. The thinnest roof plate measurement recorded was 0.304" (2004) and 0.290" (2009).

**7.5 Remaining Service Life Calculation**: The API 653 Standard does not take into account the condition of the tank roof in its recommended next inspection interval calculation. Therefore, the API 653 inspector's 2012 tank inspection report only computes the remaining service life of the tank floor and annular ring. Based on those computations, the inspector makes a recommendation for the date of the next inspection interval. In the case of the 2012 inspection, the inspector recommended the next inspection interval to be 20 years (2032).

It is prudent to also consider the condition of the tank shell and roof, especially for tanks operating vapor recovery systems, located in a seismically active area, and in an environment of heavy snow/ice loading. Based on the data collected in the 1998-2012 inspections, the thinnest roof section was found during the 2009 external inspection (0.290"), equating to 23% corrosion. Using that measurement and APSC original design standard of 0.25" minimum roof plate thickness based on an original plate thickness of 0.375" (installed in 1976) and a 0.125" corrosion allowance, the remaining service life of the roof is estimated at 17 years.

Roof corrosion should be carefully examined at the next internal inspection, especially the area around the vapor recovery nozzles and pressure relief vents, where corrosion has been found. Engineers should ensure roof thinning does not impact the roof's ability to hold the snow load or compromise vapor recovery system function.

**7.6 Roof Summary**: A summary of Tank 14's roof design and inspection data is shown in the table below.

| Tank 14 Roof Design and Inspection Data | Inspection Year | Measured Thickness |
|---|---|---|
| Roof Installed | 1976 | 0.375" |
| AUT Inspection Data | 1998 | 0.319" |
| AUT Inspection Data | 2004 | 0.304" |
| AUT Inspection Data | 2009 | **0.290"** |
| AUT Inspection Data | 2012 | 0.299" |
| Minimum required thickness for Tank 14's roof considering Valdez snow loading | | 0.250" |

[44] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 179.

## 8. Roof Support Column Inspection

**8.1 Design Information**: Tank 14's roof support column design includes 61, 24-inch diameter columns. The column design is made of 0.50" thick nominal members. The Tank 14 reports do not specify the minimum thickness for roof support members (corrosion allowance) to ensure adequate support to the roof during heavy snow loads; this value should be listed in the reports and known to the inspector.

**8.2 2012 Inspection Method**: Spot Manual Ultrasonic Testing (MUT) was used to examine each of the columns, with four (4) readings taken on each column on the north, south, east, and west faces. The column pads under the columns were inspected with MUT (where accessible). A visual inspection of the support column bases was also completed by the inspectors.[45]

**8.3 2012 Inspection Results and Repairs**: The 2012 inspection found no significant corrosion or damage to the support columns and the structure to be in good condition. The column thickness measurement (without coating) exceeded 0.500" for all 61 columns. The column pads under the columns showed less than 2% corrosion.[46]

**8.4 Comparison to Prior Inspection Results**: The 2012 support column inspection was more comprehensive than the 1998 inspection. The 2012 inspection included all 61 columns. The 1998 inspection included 1/6th of the columns (10 columns). The data from the 10 columns inspected in 1998 was compared to the 2012 data for those same columns. Four the columns measured in 1998 showed no increase or a very slight increase in corrosion in the 2012 inspection. The other six columns had thicker measurements in 2012 than 1998, as shown in the table below. While neither the 1998 nor the 2012, inspections identified corrosion concerns; it is noteworthy that there was a trend of thicker measurements made on several components of the tank in 2012.

| Support Column Number | 1998 Lowest Measurement | 2012 Lowest Measurement |
|---|---|---|
| 6 | **0.465"** | 0.513" |
| 9 | **0.485"** | 0.520" |
| 15 | **0.527"** | 0.536" |
| 22 | **0.480"** | 0.528" |
| 24 | **0.484"** | 0.523" |
| 28 | 0.516" | 0.511" |
| 35 | **0.495"** | 0.507" |
| 38 | 0.518" | 0.518" |
| 41 | 0.527" | 0.507" |
| 50 | 0.585" | 0.585" |

Actual corrosion measurements should be compared to the Tank 14 corrosion design standard for the columns. A corrosion design standard for the columns is not listed in APSC's reports.

[45] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 29.

[46] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 35 and 36.

# 9. Fire Foam System Inspection

**9.1 Design Information**: Tank 14 has a 20” fire foam system piping network installed inside the tank at the bottom.

**9.2 2012 Inspection Method**: Manual Ultrasonic Testing was used to inspect 20 random 1’ locations along the 20” fire foam systems inside the tank.

**9.3 2012 Inspection Results and Repairs**: The inspector reported “*moderate internal corrosion*” throughout the 20” fire foam system piping, with the most significant corrosion found at the base of the pipe (between the 5 and 7 o’clock position).[47] The largest wall loss measured (42%)[48] was found 70’10” downstream from the internal flange face connection. The section of pipe was originally 0.375” thick, and was measured to be 0.225” thick in 2012 (40% corrosion loss). The inspector also measured other areas of corrosion at locations from 2’6” to 88’9” downstream of the flange face connection (between the 5 and 7 o’clock position on the low side of the pipe).

Twenty (20) pipe wall thickness measurements were made. Internal corrosion was found on all 20 measurements (3% to 42% corrosion loss). Five (5), of the 20, measurements exceeded 30% wall loss.[49] No repairs were made. The inspectors report stated: “*No repairs were deemed necessary because of the significant amount of remaining wall*.”[50] APSC’s 2013 Engineering Report on the 2012 inspection concludes: “*The internal fire foam piping was inspected and no significant corrosion loss was detected. No repairs were required….The remaining piping was determined by Integrity Management to be fit for service until the next internal inspection*.”[51] The next internal inspection is planned for 2032 (20 years from the 2012 inspection). No information was provided on the minimum wall thickness required for continued safe operation.

**9.4 Comparison to Prior Inspections**: An internal API 653 inspection requires the tank to be emptied and cleaned. Sediment and sludge has historically been found in Tank 14. The fire protection system for Tank 14 includes a foam distribution system located above the tank floor at the bottom of the tank. Sediment buildup over this system can cause foam system blockages, potentially impacting foam distribution and concentration. In April 2006, the State of Alaska Department of Public Safety Division of Fire Prevention issued a letter of non-objection to the extension of the Tank 14 API 653 internal inspection interval as long as “*sediment buildup, foam spider blockages, foam distributions, and concentration will not be adversely affected by the extension of complete inspection times on the tanks*.”[52] On March 22, 2006, APSC sent the Fire Marshall a letter committing to continued monitoring and maintenance of sediment and water levels one foot below the bottom of the subsurface foam distribution piping in the tanks.[53] APSC provided test data from 2003 to 2007 to verify the Fire Foam Spider System has been successfully tested and is operational.

[47] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14’s August 2012 inspection, Page 38.

[48] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14’s August 2012 inspection, Pages 123.

[49] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14’s August 2012 inspection, Pages 121-124.

[50] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14’s August 2012 inspection, Page 38.

[51] Hally Cooper (APSC), Engineering Corrosion Report 54-TK-14, February 2013, Pages 1 and 5.

[52] VMT Internal Inspection Cycle, letter from State of Alaska Department of Public Safety Division of Fire Prevention to APSC, APSC Letter No. 8041, April 5, 2006.

[53] Tom Stokes (APSC) letter to Ron Watts (TAPS Safety Fire Marshall State Division of Fire Prevention), APSC Letter No. 8041 File 2.9, VMT Internal Inspection Cycle, March 22, 2006.

**9.5 Considerations for Next Inspection Interval**: The 2012 inspection report did not contain information on the amount of sediment build-up over the foam distribution system located above the tank floor at the bottom. This information would be useful to include in future inspection reports. It will be useful to know if the operating procedures to move sediment out of the tank have been successful in maintaining the sediment level at least one foot below the foam distribution system as agreed to by ASPC in 2006 with the Fire Marshall. If the sediment level was not one foot below the fire foam system when the tank was opened for the 2012 internal inspection, this would indicate the need for more frequent internal to clean sediment out of the tank bottom and ensure the fire foam system is not blocked.

## 10. Sump Inspection

**10.1 Design Information**: Tank 14 has one sump located around and beneath the diffuser.

**10.2 2012 Inspection Method**: A one foot (1') wide circumferential band of the sump floor and 20% of each plate of the sump wall was inspected using Manual Ultrasonic Testing. [54]

**10.3 2012 Inspection Results & Repairs**: The inspectors measured a 10% wall loss on the circumferential band and approximately 1-2% wall loss on the sump walls.[55] The crude oil diffuser sits on four separate wear plates that are seal-welded to the sump floor. The sump wear plates were weld repaired.[56]

**10.4 Comparison to Prior Inspection Results**: The prior 1998 internal inspection report prepared by APSC did not contain information on the sump condition.

## 11. Suction/Fill Line Inspection

**11.1 Design Information**: Tank 14 has a 36" Suction/Fill Line.

**11.2 2012 Inspection Method**: Manual Ultrasonic Testing was used to inspect five (5) random 1' locations along the 36" Suction/Fill Line inside the tank. [57]

**11.3 2012 Inspection Results & Repairs**: The inspectors measured a maximum corrosion loss of 4% on the 36" Suction/Fill Line inside the tank.[58] No repairs were needed.

**11.4 Comparison to Prior Inspection Results**: The prior 1998 internal inspection report prepared by APSC did not contain information on the suction/fill line condition.

## 12. Foundation Inspection

Tank 14's foundation is a concrete ring wall. A visual inspection of the foundation was completed with Manual Ultrasound Testing of the external annular ring in 2012. The 2012 API 653 inspector found the

[54] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 12.
[55] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 12.
[56] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Pages 10 and 12.
[57] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 39.
[58] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 39.

seal around the bottom of the tank had "*mostly failed*" with vegetation and root systems prevalent and no significant damage to the external portion of the annular ring that can be seen outside the tank.[59] The seal is used to prevent water from running beneath the tank. Vegetation and root systems can damage the liner and foundation. The API 653 inspection report did not state what, if any repairs were made to the seal around the bottom of the tank. The 2013 APSC Engineer's Report of the 2012 inspection was silent on the foundation inspection findings and any repairs, if any. The 2009 external inspection did not identify any problems with the foundation.

## 13. New Stair Design

The 2012 inspector's report noted that, "*A new stair design has been implemented for all of the VMT Oil Storage Tanks because of continued damage from falling snow and ice. The original stairs wrapping around the tanks have been replaced with roof-access stars from the center platforms*."[60]

## 14. Cathodic Protection System

In 1998, a cathodic protection system was installed under Tank 14 and a new tank floor was installed.[61] Tank 14's floor was replaced due to significant soil side corrosion that occurred during the period of 1976 (original tank installation date) to 1998 when the tank was not protected by a cathodic protection system.

Steel tanks (like Tank 14) can corrode when a natural electrochemical reaction occurs between the tank and the surrounding soil. Steel naturally reacts with water (contained in the soil) and oxygen to convert the steel alloy to its more stable chemical state (iron oxide; more commonly called "rust"). Cathodic protection systems interrupt this natural reaction, to eliminate (or slow) the reaction process. Several types of cathodic protection can be used to mitigate tank corrosion. Tank 14 has an impressed current cathodic protection system that provides direct current to the tank to interrupt the natural electrochemical reaction.

The corrosion process includes four components: (1) an anode, (2) a cathode, (3) a metallic path connecting the anode and cathode, and (4) an electrolyte. For corrosion to occur, areas with different electrical potentials (anodes and cathodes) must be present on a tank's surface. Corrosion occurs at the anode. At an anode location on the tank, the tank's metal goes into solution (corrodes) by releasing electrons and forming positive metal ions. The anode has a lower electronegative potential than the cathode. Current flows from the anode to the cathode to complete the corrosion reaction. At a cathode location on the tank, a chemical reaction takes place that uses the electrons released at the anode. No corrosion takes place at a cathode. Because steel is not homogeneous, (it is made of various alloys and may be welded with metals that slightly vary from alloys in the tank floor plates) there are differences in the electrical potential from one area to another along the tank. Therefore, the same piece of steel can provide both the anode and the cathode. The metallic path provides a way for electrons released at the anode to flow to the cathode completing the reaction circuit. Since steel conducts electricity, adjacent cathodic and anodic areas on a steel plate have a metallic path. The last component needed for a corrosion reaction is the electrolyte. The electrolyte is a conductive environment (e.g., wet soil or water) that supplies the reactants necessary for corrosion to occur. Snow, rain, and water draining down the

---

[59] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 40.

[60] Team Peak Alaska Report, prepared for APSC December 2012, on Tank 14's August 2012 inspection, Page 40.

[61] APSC Report 1998, Appendix H- X058, Tanks 13 and 14 CP System Commission Report. PWSRCAC does not have a copy of this report; however, this report is referenced in APSC documents as the technical report that documents the Tank 14 CP system commissioning.

mountainside behind the tank farm provide wet soil beneath Tank 14 providing the electrolyte needed for the corrosion reaction. Water and sludge inside the tank also provide an electrolyte.

In the simplest type of cathodic protection a sacrificial anode is installed on a metal surface (e.g., a zinc anode installed in a marine engine) to ensure corrosion occurs on a sacrificial metal plate that can be periodically replaced. Impressed current cathodic protection systems are used to reverse the natural electrochemical reaction on larger steel surfaces like Tank 14.

An impressed current system prevents tank floor corrosion by converting all of the anodic (active) sites on the tank floor to cathodic (passive) sites by supplying electrical current to another buried impressed current anode (separate from the tank), installed below the tank. Tank 14's impressed current cathodic protection system uses Mixed Metal Oxide (MMO) ribbon anodes in a grid and perimeter ring orientation under the tank floor. The anodes are buried approximately 9" below the tank both on 2'6" center spacing.[62]

An impressed current system uses a rectifier to convert alternating current (AC) (provided by the VMT power system) to direct current (DC). Rectifier[63] 54-DPS-14-1 supplies power to Tank 14's anode grid.[64] Electrical current flows from the buried impressed current anode through the wet soil (the electrolyte) and onto the tank bottom causing a build-up of hydrogen ions on the tank floor.[65] The hydrogen ion film blankets the tank bottom and reduces the rate of corrosion (this is also called a "polarization film"). The tank bottom then becomes a cathodic passive site where corrosion is less likely to occur.

When a structure (such as a tank bottom) is cathodically protected, it can take days to months to become polarized. Therefore, consistent and reliable operation of an impressed current cathodic protection system is critical to maintain corrosion protection.[66]

To ensure the CP system is working effectively, a soil-to-structure potential test is conducted to verify a film of negatively-charge ions is forming across the tank bottom. This test verifies there is enough current by measuring the potential of the tank's steel against a standard reference electrode. APSC uses copper/copper sulfate ($Cu/CuSO_4$) reference electrodes as a standard reference. The soil-to-structure potential test is completed using a direct current (DC) voltmeter and a reference cell (a reference electrode in contact with the electrolyte (the wet soil)).

For large tanks, like the Valdez Marine Terminal Crude Oil Storage Tanks (250' diameter) it is important to measure the soil-to-structure potential at various points around and under the tank. At Tank 14, six (6)

---

[62] 2002 TAPS Valdez Marine Terminal Cathodic Protection Survey, WO# 32000354-01, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., December 30, 2002.

[63] A rectifier converts standard 110-volt alternating current (AC) electricity from the power grid to direct current (DC). The direct current from the rectifier powers buried anodes that provide the electrons to protect the tank bottom. Rectifier 54-DPS-14-1 supplies power to the anode grid and has a maximum voltage rating of 50 volts at 80 amps (which was determined to be sufficient to cause current to flow from the anodes to the tank and not exceed the current output of the anodes above the manufacturer's rating).

[64] Project L019, 1999 Annual Cathodic Protection Survey of the Valdez Marine Terminal and SERVS Facility, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., January 2000.

[65] The AC power cable is connected to the rectifier input terminals. The rectifier output DC positive cable is connected to the Mixed Metal Oxide ribbon anodes. The output DC negative terminal is connected to the tank. Current is sent through the electric wire to the anodes buried below the tank. The current then flows from the anodes through the soil to the tank and returns to the rectifier through a wire attached to the tank. The current going to the tank needs to sufficient to overcome the corrosion-causing current naturally flowing away from it.

[66] Meyers, P.E., Above Ground Storage Tanks. McGraw-Hill, 1997.

permanently installed copper/copper sulfate ($Cu/CuSO_4$) reference electrodes are installed to monitor the CP system. Three (3) monitoring tubes are also installed under the tank, spanning the tank floor. A portable reference electrode is used in the monitoring tubes to periodically collect measurements. It is important to make measurements under the tank, because measurements at the perimeter of the tank may not represent the tank-to-soil potential under the center of the tank, especially for such a large tank.

The soil-to-structure potential test can be conducted with the CP system operating (“On”) or with the CP system temporarily interrupted off (I/Off). The “On” reading can include a significant error caused by measuring the current flowing through the soil; therefore, it is standard practice to take the measurement with the protective current temporarily interrupted off (I/Off). National Association of Corrosion Engineers (NACE) Recommended Practice (RP-0193-93) standard for structure-to-soil potential is -850mV (or more negative) with respect to a $Cu/CuSO_4$ reference electrode with the protective current temporarily interrupted off (I/Off). The natural potential is about -500mV when measured against a reference copper sulfate electrode. Values that are more positive represent steel that has undergone corrosion. Values that are more negative indicate steel has been protected from corrosion.

NACE has a second standard called the “100 mV shift criteria,” or “100 mV polarization” that compares the protective current temporarily interrupted off (I/Off) reading to the potential measured prior to the application of cathodic protection (the “native” or depolarized” potential). The 100 mV shift criteria is met if the instant off voltage minus the depolarized voltage readings is at least 100 mV.

Typically, the structure-to-soil potential is tested to see if it measures at least -850mV (or more negative), if so, the inspector has verified the CP system is functioning effectively. If the -850 mV criteria is not met, it is an indication that the CP system may not be functioning effectively. Additional testing is completed to obtain a depolarization potential to determine whether the 100 mV shift criteria can be met.

Cathodic protection system records for 1999 to 2011, and 2013 to 2014 were provided by APSC. The cathodic protection system remained operational from 1999 to 2014 (except May 2005 and November 2005 when the CP system was damaged, with a few outages during periods of maintenance, inspections, and repairs. Please see Attachments No. 1 and 2 to this report for a summary of the data.

Cathodic protection system data for 2012 was not available. Tank 14 was inspected in 2012. The cathodic protection system was turned off during the inspection. It is unclear why cathodic protection system testing was not completed later in the summer or early fall of 2012 when the tank inspection was complete, and the system resumed operation.

APSC substantially reduced the number of cathodic protection system test points it measured under Tank 14 from 54 test points in 1999-2008 to only 10 test points in 2009 to 2011 and 2013. In 2010, PWSRCAC raised concern about the reduced number of test points. In 2014, APSC resumed the higher testing frequency to 50 test points. NACE RP-0193-93 recommends that on tanks greater than 60’ cathodic protection system test points be collected both at the perimeter and under the tank, because measurements at the tank perimeter may not reflect actual conditions.

PWSRCAC should note that APSC stamped the 2011, 2013, and 2014, Cathodic protection system data with this limitation: “*NOTICE: This document is the property of the owners of the trans-Alaska Pipeline System and the drawing/document and information contained shall not be duplicated, used, or disclosed, except as authorized by the agent, Alyeska Pipeline Service Company*.” It is recommended that PWSRCAC consult with APSC on the use of this data, in this report, and obtain approval before the report is distributed.

## 15. Recommendations

A list of recommendations is provided below for PWSRCAC to consider for future crude oil tank inspections:

**15.1 Number of Inspection Points on Shell and Roof Inspections**. It is recommended that the number and location of additional shell and roof corrosion loss measurements be increased. External API 653 inspections are completed every 5 years. External inspections provide a more frequent opportunity to monitor the shell and roof corrosion rate during the 20 year period before the next out-of-service API 653 inspection. In the past, only three corrosion measurements have been taken on each shell course ($2^{nd}$ to $8^{th}$), usually in approximately the same location each inspection (along the stairs) or from a man lift. This is a low number of measurements for a 250' diameter tank. As the tank ages, it would be beneficial to consider collecting additional measurement locations on each shell course during the 5-Year API 653 external inspections (especially if inspection data shows increasing corrosion). The past amount of roof corrosion data collected (52 points across the roof has been useful); however, the 2012 inspection had a substantial decrease in the number of inspection points and total amount of roof area inspected.

**15.2 Evaluation of Corrosion Trends Using All Inspection Data**. API 653 Section 6 requires an inspection history to be maintained on the tank, including corrosion rate and inspection interval calculations. It is recommended that the scope of work requested by APSC for its API 653 inspectors, include review of prior inspections, re-measurement the areas of highest corrosion loss found in the prior inspection to determine whether corrosion loss has increased or stabilized, and an explanation of any measurements that are not consistent with past corrosion measurements or trends. Neither the 2012 inspector's report, nor the 2013 APSC Engineer's summary of the 2012 inspection evaluated corrosion trends based on prior inspection data.

For example, prior inspections measured annular ring and roof corrosion that exceeded the measurements reported in 2012. It is possible the 2012 inspector found its measurements to be more accurate, using newer technology, discounting the prior inspection data. However, it would have been useful for the 2012 inspection report to acknowledge prior measurements, explain what work was done to more thoroughly investigate those areas of known "worst-case" corrosion loss from the prior inspections, and explain why the new, 2012 thicker measurements were more accurate. Absent re-measurement, or an explanation of why prior data should not be considered, the most conservative corrosion data should be used in remaining service life computations.

**15.3 Corrosion Loss Computation**. Corrosion loss is computed by taking the difference between the original tank plate thickness and the plate thickness measured in the inspection. In the 2012 Tank 14 inspection report, the inspector used the base metal thickness (area adjacent to the corrosion found), rather than the original plate thickness to compute the roof and annular plate corrosion loss, underestimating the corrosion loss.

**15.4 Risk Reduction Through More Frequent Inspections**. Future corrosion rates may increase or decrease based on a number of factors. Corrosion rate estimates based on previous tank operating history are only a guide and do not provide a guarantee of future corrosion rates. Routine inspections are a critical part of an oil spill prevention program. Due to the size, age, and location of this tank in a critically sensitive habitat area, it is recommended that a minimum inspection regime of 10 year API 653 out-of-service inspections and 5 year API 653 in-service inspections be maintained, with inspections that are more frequent if corrosion loss data warrants. Extending the

API 653 out-of-service interval to the maximum 20 year interval allowed, based solely on the estimated remaining service life of a new tank floor installed in 1998 does not take into consideration that by the next out-of-service inspection proposed (Year 2032) all the other tank components will be 56 years old, or the highly sensitive location.

API 653 recommends that in addition to completing the standard "next inspection interval computation" (based solely on the remaining floor and annular plate thickness), that the inspector also consider several other factors when setting the tank inspection interval, such as: "(*a) the nature of product stored, (b) The results of visual maintenance checks, (c) Corrosion allowances and corrosion rates, (d) corrosion prevention systems, (e) conditions at previous inspections, (f) the methods and materials of construction and repair, (g) the location of the tanks, such as those in isolated or high risk areas, (h) The potential risk of air or water pollution, (i) leak detection systems, (j) change in operating mode, (k) jurisdictional requirements, (l) changes in service (including changes in water bottoms), (m) the existence of a double bottom or a release prevention barrier.*

More frequent out-of-service inspections provide the opportunity to evaluation the condition of all aging components of Tank 14, not just the new tank floor. More frequent out-of-service inspections also provide the opportunity for the operator to: clean out sediment buildup that can obstruct the fire foam system installed in the bottom of the tank; repair damaged coating that protects the tank floor and lower section of the tank where corrosive water and sediment can build; provides earlier identification of tank floor leaks that could be significant and cumulative, but may fall below the leak 3,000 barrel detection threshold of the sensitive gauging system installed on Tank 14. Tank 14 does not have any leak detection system installed below the tank floor that would alert the operator to a continuous leak that falls below the 3,000 barrel threshold.

**15.5 Fire Foam System Inspection, Repair, and Replacement**. The 20" fire foam system is an important component of safe tank operation. Internal corrosion of up to 42% pipe well loss was measured, and no repair or replacement was recommended by the inspector. It would be useful for APSC to clarify the acceptable minimum pipe wall thickness allowed for the 20" fire foam piping and the threshold at which repair or replacement will be conducted. The inspector recommended the next inspection to be completed in 2032, 20 years from the date that the 42% corrosion loss measurement was taken. It will be important to understand the date the fire foam piping was installed in Tank 14, and the projected date the 20" line may fail if internal corrosion loss continues at its current corrosion rate; and, how that projected date compares with the recommended 20 year inspection interval. It may be useful for PWSRCAC to have its Fire Protection experts evaluate this data.

**15.6 Foundation Repairs**. The 2012 API 653 inspector found the seal around the bottom of the tank had "mostly failed" with vegetation and root systems prevalent. The API 653 inspection report did not state what, if any repairs were made to the seal around the bottom of the tank. It would be useful to clarify with APSC if the seal repairs have been completed.

**15.7 Roof Support Corrosion Allowance**. Tank 14's roof support column design includes 61, 24-inch diameter columns. The column design is made of 0.50" thick nominal members. The Tank 14 reports do not specify the minimum thickness for roof support members (corrosion allowance) to ensure adequate support to the roof during heavy snow loads; this value should be listed in the reports.

**15.8 Cathodic Protection System Operation**. The cathodic protection system plays an important role in protecting Tank 14's floor from soil-side corrosion. Continued annual monitoring of the cathodic protection system operability, collecting data at 10' intervals along each reference cell tube, and at the permanent reference cells should continue.

**15.9 Report Distribution**. PWSRCAC should note that APSC stamped the 2011, 2013, and 2014, Cathodic protection system data with this limitation: "*NOTICE: This document is the property of the owners of the trans-Alaska Pipeline System and the drawing/document and information contained shall not be duplicated, used, or disclosed, except as authorized by the agent, Alyeska Pipeline Service Company*." It is recommended that PWSRCAC consult with APSC on the use of this data, in this report, and obtain approval before the report is distributed.

## 16. Acronym Summary

| | |
|---|---|
| ADEC | Alaska Department of Environmental Conservation |
| API | American Petroleum Institute |
| API 653 | American Petroleum Institute Standard No. 653 |
| APSC | Alyeska Pipeline Service Company |
| AUT | Automated Ultrasonic Testing |
| CP | Cathodic Protection |
| C-Plan | Oil Discharge Prevention and Contingency Plan |
| EMAT | Electromagnetic Acoustic Transmission |
| $ft^2$ | Square feet |
| $ft^2$ | Square inch |
| NACE | National Association of Corrosion Engineers |
| mpy | Mils per year (mpy), where a "mil" is a thousandth of an inch (0.001 inch) |
| MFL | Magnetic Flux Leakage |
| MMO | Mixed Metal Oxide |
| MUT | Manual Ultrasonic Testing |
| PWSRCAC | Prince William Sound Regional Citizens Advisory Council |
| PT | Penetrant Testing using dye |
| RP | Recommended Practice |
| RT | Radiographic Testing |
| Tank 14 | Crude Oil Tank No. 14 |
| VMT | Valdez Marine Terminal |
| WFMT | Wet Fluorescent Magnetic Particle Testing |