Harvey Consulting, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Linda Swiss	Austin Love
PWSRCAC	PWSRCAC
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May 18, 2015

Dear Ms. Swiss and Mr. Love,

On March 31, 2015, I provided a report summarizing 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. 13 (Tank 13), and available Cathodic Protection (CP) data for Tank 13. This report noted missing cathodic protection system data from 2003 to 2007. The March 2015 report was approved by PWSRCAC. The March 2015 has been amended to include the 2003 to 2007 cathodic protection provided by APSC, along with a more detailed explanation of how an impressed current cathodic protection system works to reduce or eliminate tank bottom corrosion.

This report summarizes the findings of the 196 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 (installed in 1998) has remained operational and protective during the period of 1999 to 2014.

Overall, I found the 2012 Tank 13 inspection report to be very thorough, well documented, and technically supported. The quality of the Tank 13 API 653 inspection report was a substantial improvement over the crude oil tank inspection reports previously provided to PWSRCAC. For example, Tank 13's 2012 inspection report included: tables showing all 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 13 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 2014, with a few outages during periods of maintenance, inspections, and repairs. 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

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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. 13 (Tank 13) 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 13, and available Cathodic Protection (CP) data for Tank 13. This report summarizes the findings of the 196 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 to 2014. More specifically, PWSRCAC requested that Harvey Consulting, LLC review the two reports provided by APSC for the 2012 Tank 13 API 653 inspection.

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

(2) The API 653 inspector's Report prepared by Thomas Hazlett, Team Peak Alaska, for APSC on September 4, 2012, summarizing the June 2012 inspection.

Additionally, Harvey Consulting, LLC compared the 2012 inspection results to the results of three prior inspections completed on Tank 13 [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 13 Inspection Findings

2.1 A new tank floor was installed in 1998. A maximum floor plate corrosion loss of 17% 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 37.4 years for the tank floor.

2.2 A round bulge (4.5" in diameter by 0.1875" high) was found in a floor plate during the 2012 inspection and was repaired. The 2012 inspector concluded the dent was likely caused by blunt force (e.g., forklift) during the 1998 tank floor installation.

2.3 Significant weld gouges were found in the annular ring, requiring repair. The 2012 inspector concluded these gouges were created during the 1998 new tank floor installation. The record is unclear on why these gouges were not repaired in 1998.

2.4 All annular ring plate measurements taken in 2012 exceeded the minimum required plate thickness of 0.580"; however, the thinnest 2012 inspection measurement (0.687") was higher than the prior

1998 inspection measurements of 0.605” remaining thickness (general corrosion loss), and 0.495” remaining thickness (isolated corrosion pitting). While prior measurements of corrosion pitting deeper than 0.580” remaining thickness were recorded in 1998 at 0.495” remaining thickness, APSC engineers attribute those measurements to isolated pitting and concluded the 0.580” minimum thickness threshold did not apply to isolated pitting. The 0.495” remaining thickness corrosion pit was not repaired in 1998 and was sealed beneath the new floor lap joint on the annular ring.

2.5 Tank 13’s shell has very little corrosion. The highest amount of corrosion (8%) was measured at the top of the tank near the roof. 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).

2.6 Very little of the roof was inspected in 2012. Tank 13’s roof area is larger than one acre. Less than 0.5% of the roof was inspected, and the inspection was limited to three roof plates. The inspector reported a minimum roof plate thickness of 0.307,” and a maximum 7% corrosion loss. The prior 2009 external roof inspection collected 52 roof measurements by sampling 13 points along the roof in the north, east, south, and west compass directions. The thinnest roof plate measurement recorded in 2009 was 0.292”, equating to a 22% roof plate corrosion loss from the original roof plate thickness of 0.375”, and a remaining service life of 17 years.

2.7 Sixty (60) of Tank 13’s 61 internal roof support columns had no corrosion, and one column had less than 1% corrosion.

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

2.9 Tank 13 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. Neither the 2012 inspection report, nor the APSC Engineer’s report that followed in 2013, explained what (if any) repairs were made to the seal around the bottom of the tank. The prior 2004 external inspection also recorded the sealant at the bottom of the tank and the top of the concrete foundation was loose or missing, and that vegetation was growing around the perimeter of the tank.

2.10 The 20” fire foam system piping network installed inside the tank at the bottom showed internal corrosion. The most significant corrosion was found 56’7” downstream from the internal flange face connection (53% wall loss). No repairs or replacements were made. No information was provided on the minimum wall thickness required for continued safe operation.

2.11 The 2012 inspector recommended Tank 13’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.

2.12 Cathodic protection system records for 1999-2011, and 2013-2014 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, with three exceptions (reference cell #2 in Years 2002, 2006, and 2011).

2.13 Tank 13 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.

2.14 APSC substantially reduced the number of cathodic protection system test points it measured under Tank 13 from 41 test points in 1999-2002 to only nine (9) test points in 2009-2011. In 2010, PWSRCAC raised concern about the reduced number of test points. In 2013 and 2014, APSC resumed the higher testing frequency to 39 test points.

3. Tank 13 Construction and Inspection History

Tank 13 is a crude oil storage tank at the Valdez Marine Terminal (VMT). Tank 13 was built on site at the VMT in 1976. As of this report (Year 2015), Tank 13 is 39 years old. Tank 13 is a carbon steel tank with a concrete ring wall and a fixed welded cone roof, and welded shell.

Tank 13 is 62'4" tall, and 250' in diameter. If filled full, Tank 13 can hold 546,526 barrels. However, APSC limits the fill level to 58'6". Tank 13's maximum storage capacity at the 58'6" fill level is 510,000 barrels.[1]

A 1992 internal tank inspection found three holes in Tank 13's floor, all within a single 2 square foot (ft^2) area. Each hole was less than ¼" in diameter. APSC reported no visible contamination of underlying soil and reported soil side corrosion as the likely cause of the holes in Tank 13's floor. Tank 13 was in operation for 16 years (from 1976-1992), without cathodic protection at the time these holes were found.[2]

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 13 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]

The first full API 653 out-of-service inspection was completed in 1998 (internal and external inspection). The inspection was completed after the new tank floor was installed, to verify the tank was suitable for return to service. 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, and the agencies approved, a four year extension of time to complete the next API 653 out-of-service inspection until 2012. PWSRCAC opposed this inspection interval extension.[5] This 2012 inspection is the second API 653 (out-

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

[2] Alyeska Pipeline Service Company (APSC), X058 Tank 13 Review, August 27, 2002.

[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] PWSRCAC opposed the inspection delay for the following reasons: there was no evidence provided by APSC that 1998 inspection was completed by a API 653 inspector; one annular ring plate had corrosion that exceeded APSC's design criteria in

of-service) inspection for Tank 13. The third inspection is planned for year 2032, when Tank 13 will be 56 years old.

4. Floor Inspection

4.1 Design Information Tank 13's floor, installed in 1998, was made of 0.260" thick welded steel plates. The tank floor was coated with Devoe Bar Rust 236 approximately 0.012" – 0.016" thick.

4.2 2012 Inspection Method: Tank 13's floor was inspected using a Magnetic Flux Leakage (MFL) tool. Manual Ultrasonic Testing (MUT) was also used to verify Magnetic Flux Leakage tool indications during the initial inspection and to inspect any areas that were not accessible to the Magnetic Flux Leakage scanner. A visual inspection of the shell-to-floor weld was completed.[6]

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. The inspector speculated the minor chips may have occurred during the tank cleaning preparation for the 2012 inspection. No significant internal corrosion damage was found in the coated area.

Four (4) floor plates were identified by using the Magnetic Flux Leakage tool for follow-up Manual Ultrasonic Testing. The highest corrosion found on floor plate FP-146 was attributed to soil-side corrosion (from the bottom of the tank floor), equating to a 17% corrosion loss since the new tank floor was installed in 1998.[7]

A round bulge (4.5" in diameter by 0.1875" high) was found in floor plate FP-030. A 6" x 6" section of the plate containing the bulge was removed and a 1' x 1' plate was installed as a patch.[8] This repair met the API 653 minimum standard of a welded-on patch plate repair to a floor.[9] The inspectors report stated: "*the dent appeared to have been caused by blunt force presumably from a forklift during construction of the tank floor, as there was nothing directly underneath the indication to cause the plate to bulge upwards*."[10]

4.4 Comparison to Prior Inspection Results: The 1998 inspection did not identify the round bulge (4.5" in diameter by 0.1875" high) in floor plate FP-030. It is unknown when this bulge occurred, between 1998 and 2012. The 2012 inspector speculated it occurred in 1998 during installation of the new floor. If that was the case, the bulge should have been identified by the inspector in 1998 and repaired before the tank was returned to service.

4.5 Remaining Service Life Calculation Based on 2012 Inspection Results: The floor plate thickness of the tank floor was 0.260" in 1998. The maximum corrosion depth found during the 2012 inspection was 0.044." Therefore, the lowest remaining floor thickness was computed to be 0.216."

1998; two annular plates had significant corrosion pitting that were not repaired and were extrapolated to fall below APSC's design standard thickness of 0.58" by the next inspection; sediment and sludge had been found in Tank 13 over the 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.

[6] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.

[7] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 12.

[8] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 10.

[9] API 653 Standard, Chapter 9, Tank Repair and Alteration.

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

Using the maximum floor corrosion found since 1998 (0.044") 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 0.0031" 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.[11] Using the lowest remaining floor thickness measured during the 2012 inspection, in the area with the highest corrosion (0.216") and ensuring a 0.100" remaining floor thickness by the next inspection, a corrosion allowance of 0.116" was computed.

The 2012 inspector assumed the corrosion rate exhibited from 1998 to 2012 (0.0031" per year) would remain linear, with no future acceleration.[12] Based on this assumption, the API 653 inspector computed a remaining service life of 37.4 years[13]

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

Tank 13 Floor Design and Inspection Data	Inspection Year	Measured Thickness
New floor installed	1998	0.260"
MFE and MUT Inspection Data	2012	0.216"
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. 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 13) that use thickened annular plates for seismic considerations, be established by a seismic engineering evaluation, using the actual thickness of the existing annular plate.[14] 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 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 13's annular ring plates were inspected using an Electromagnetic Acoustic Transmission (EMAT) system and Manual Ultrasonic Testing (MUT).[15] The critical zone of the annular ring (the 3" section of annular plate adjacent to the tank shell, measured from the

[11] API 653 Standard, Chapter 6.

[12] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 9.

[13] 37.4 years= (0.116" corrosion allowance/ 0.0031" corrosion rate per year).

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

[15] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 21.

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.[16]

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. The inspector computed corrosion rates up to 14% maximum (Plate A10) at a remaining thickness of 0.687" from the original 0.815" plate thickness.

There was top-side damage caused by air carbon arc gouging during the 1998 floor replacement. Plates A14, A20, A22, and A33 had gouges greater than 0.100" deep. Gouges over 0.100" were weld-repaired.[17] For example, one gouge on plate A22 was measured at a 19% plate loss.[18] Other top-side annular ring plate weld anomalies from the 1998 tank floor installation were also found and repaired.[19] Neither the 2012 inspector's report, nor the 2013 APSC engineering summary of the 2012 inspection, explained why these significant gouges (created during the 1998 floor replacement) were not repaired before Tank 13 was returned to service in 1998. The 1998 inspection report confirmed the 1998 inspector was aware of the arc gouging damage, the report stated: "*and arc gouge with a depth of 0.148" was noted on annular ring plate A20*." Repair of this pit was not necessary since the remaining material thickness was not below the critical value of 0.580" and that "*all the topside pits in the annular ring were due to the arc gouging process and not to actual corrosion attack.*"[20]

5.4 Comparison to Prior Inspection Results: API 653 Section 6 requires an inspection history to be maintained on the tank, including corrosion rate and inspection interval calculations. The prior internal inspections in 1992 and 1998 measured annular ring corrosion that exceeded the measurements reported in 2012.[21] 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 1992 and 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 1992 and 1998 data sets (if that was the case).

In 1998, Manual and Automated Ultrasonic Testing was used to examine 100% of the exposed surface of the annular plate ring. Thirty 12" x 12" scans were completed on random annular ring plates. The 1998 inspection showed corrosion on the annular ring plates with the most significant corrosion on plates A10, A15, and A16.[22] A deep corrosion pit with a remaining thickness of 0.495" was found on Plate A10. APSC engineer's report summarizing the 1998 inspection described this pitting as "isolated," that a repair was not needed until the pit reached a minimum

[16] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.

[17] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 9.

[18] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 53.

[19] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 9.

[20] TK-13, Internal Inspection Report Excerpts (1992) and (1998) provided by APSC to ADEC as part of its request to defer the 2008 out-of-service inspection date, pdf Page 2830.

[21] TK-13, Internal Inspection Report Excerpts (1992) and (1998) provided by APSC to ADEC as part of its request to defer the 2008 out-of-service inspection date.

[22] TK-13, Internal Inspection Report Excerpts (1992) and (1998) provided by APSC to ADEC as part of its request to defer the 2008 out-of-service inspection date.

plate thickness of 0.406." The APSC engineer concludes the 0.580" minimum threshold does not apply to isolated pitting. The 0.495" corrosion pit was not repaired in 1998 and was sealed beneath the new floor lap joint on the annular ring. APSC's engineer's report stated: "*this location was under the lap joint of the floor onto the annular plate and will not be inspected during the next internal inspection cycle*."[23]

More significantly, the 1998 inspector measured and reported Plate A15's remaining thickness at 0.605" (general corrosion plate loss). A remaining thickness of 0.605" comes close to Aiken Engineering's recommended minimum thickness of 0.580" for the annular plate ring. The 2012 inspection report includes one EMAT reading taken on Plate A15; that reading measured a remaining thickness of 0.800" (less than 2% corrosion loss), which is substantially thicker than the lowest reading taken in 1998. UT measurements on Plate A-15 in the critical zone measured a remaining thickness of 0.825." The 2012 inspection report did not explain why the 1998 and 2012 measurements differed.

The 2012 inspection closely examined the condition of Plate A10.The 1998 inspection found a deep corrosion pit with a remaining thickness of 0.495" on Plate A10 (as explained above). The 2012 inspector's report listed the deepest corrosion pit on Plate A10 to have a minimum remaining thickness of 0.687" and described the corrosion loss to be "isolated, soil-side corrosion pitting." The 2012 inspection report did not explain why the 1998 and 2012 measurements differed.

Instead, the 2012 inspection report concluded the minimum remaining thickness of 0.687" of A10 (the highest corrosion) exceeded the minimum required plate thickness of 0.580," and was silent on the higher corrosion measurements from 1998, or why the 2012 data was more reliable.

5.5 Remaining Service Life Calculation: The annular ring plate thickness of the ring plates installed in 1976 was 0.8125." The 2012 inspection reported a maximum corrosion depth of 0.125." The inspector's report stated this was an isolated, soil-side corrosion pit, where the remaining plate thickness was measured at 0.687", and the nearby plate thickness was measured at 0.795". A remaining plate thickness of 0.687" equates to a 14% corrosion loss since the tank was installed in 1976.

Using the maximum annular ring plate corrosion found since 1976 (0.125") 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 0.0035" per year. Using the lowest remaining annular ring plate thickness during the 2012 inspection, in the area with the highest corrosion (0.687") and ensuring a 0.580" remaining plate thickness by the next inspection, a corrosion allowance of 0.107" was computed. The 2012 inspector assumed that the corrosion rate exhibited from 1976 to 2012 (0.00347" per year) would remain linear in the future.[24] Based on this assumption, the API 653 inspector computed a remaining service life of 30.8 years (0.107" corrosion allowance/ 0.00347" corrosion rate per year). If the 1998 corrosion data was used to compute the remaining service life it would be substantially shorter. Therefore, it is important for APSC to be sure the 1998 data was invalidated by the new data collected in 2012 and explain why a shorter, more conservative remaining service life should not be used.

[23] X058 TK 13 APSC Memorandum, from Kelly Lee to Tom Stokes, Summarizing the 1998 out-of-service inspection on Tank 13, August 27, 2002.

[24] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 9.

The 2013 APSC engineering report, of the 2012 Tank 13 inspection, computed a remaining life of 168 years for the annular plate using a minimum thickness of 0.100" allowed by API 653, in areas that are not seismically active. 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 2012 inspector's report correctly used the 0.580" remaining plate thickness estimated by Aiken Engineering to compute the estimated remaining service life of the annular plate at 30.8 years.

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

Tank 13 Annular Ring Plate Design and Inspection Data	Inspection Year	Measured Thickness
Annular Plate Installed	1976	0.8125"
AUT Inspection Data (general plate corrosion)	1992	0.6800"
MUT and AUT Inspection Data (isolated pit)	1998	0.4950"
MUT and AUT Inspection Data (general plate corrosion)	1998	0.6050"
EMAT and MUT Inspection Data (isolated pit)	2012	0.6870"
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 13 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.[25]

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 13's 8th shell course (6.67 ft^2) was scanned using an Automated Ultrasonic Testing system.[26] Manual Ultrasonic Testing was used to inspect Tank 13's shell courses 2-7 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

[25] The API 653 standard, *Minimum Thickness Calculation for Welded Tank Shell*, does not apply to tank diameters in excess of 200.' Tank 13'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*."

[26] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8, and 28.

shell nozzle and each roof nozzle, and four (4) readings on each support column.[27] Measurements were made on the south side of shell courses 2nd -7th using a man lift.[28] Three measurements were made on each shell course (2nd -7th); 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.

6.3 2012 Inspection Results & Repairs: The inspector measured no corrosion on the 2nd, 3rd, and 4th shell courses, 1% corrosion on the 1st and 5th shell courses, 2% corrosion on the 6th shell course, 3% corrosion on the 7th shell course, and 5% corrosion on the 8th shell course.[29] The inspector concluded there was no significant corrosion activity on the shell nozzles.[30]

6.4 Comparison to Prior Inspection Results: Prior inspections measured minimum remaining shell thickness in 1998 (internal), 2004 (external), and 2009 (external). The data collected in 2012 was generally consistent with the prior data collected, showing minor to no corrosion on most of the shell courses (1st through 7th) with 5-8% corrosion on the 8th course (at the top of the tank). The 2009 external inspection measurements showed slightly thinner shell walls than recorded by the 2012 inspector for the 1st, 7th, and 8th courses (as shown in red highlights in the comparison table below); however, the differences are not significant and don't affect the overall conclusion made by the 2012 inspector that there was no significant corrosion activity. A summary table of the prior inspections is shown below.

Tank 13, 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	0.491	0.488	**0.459**	0.493	8%	0.0011	>20
7	0.500	0.125	0.375	> 0.500	0.497	**0.469**	0.485	6%	0.0009	>20
6	0.500	0.125	0.375	> 0.500	> 0.500	> 0.500	**0.490**	2%	0.0003	>20
5	0.569	0.125	0.444	> 0.569	> 0.569	0.547	**0.564**	1%	0.0001	>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	*	> 0.969	0%	0.0000	>20
1	1.121	0.125	0.996	> 1.121	1.100	**1.100**	1.105	2%	0.0006	>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.

The 1998 internal inspection obtained ultrasonic measurements on all (18) plates that make up the 1st course of the tank shell. Ultrasonic inspection of the second through eighth courses was completed from the tank staircase. Thickness measurements of the 1st through 7th courses exceeded the original design nominal thickness. Corrosion was found on the 8th course where the shell plate thickness had minor corrosion, reducing the thickness from the original 0.500" to 0.491."

The 2004 external inspection obtained 36 ultrasonic measurements on the 1st tank course. Most measurements exceeded the original design thickness of 1.121" thick. The lowest measurement on

[27] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.

[28] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 26-27.

[29] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 11.

[30] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 10.

the 1st course was 1.100” thick. The 2004 external inspection obtained one ultrasonic measurement on each of the 2nd through 8th tank courses. Measurements for the 2nd through 6th tank courses exceeded the original design nominal thickness. The 7th course measurement was only slightly below the original design thickness (0.497”) and the 8th course was measured at 0.488”.

The 2009 external inspection obtained 36 ultrasonic measurements on the 1st tank course. Most measurements exceeded the original design nominal thickness of 1.121” thick. The lowest measurement on the 1st course was 1.100” thick. The 2009 external inspection obtained one ultrasonic measurement on each of the 5th through 8th tank courses. No measurements were taken on the 2nd through 4th course due to stair damage prohibiting inspector access. Measurements on the 6th tank course exceeded the original design nominal thickness. The 5th, 7th and 8th course measurements were only slightly below the original design thickness, with measurements of 0.547”, 0.469”, and 0.459” respectively.

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 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 to 2012 inspections, the remaining service life of the shell is estimated at 74 or more years, based on the highest corrosion rate measured at the top of the tank shell (8th course), and an assumption that corrosion will not accelerate in the future. Because Tank 13 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 13 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.

7. Roof Inspection

7.1 Design Information: Tank 13's roof was originally made of 0.375" thick, welded steel plates, placed over structural steel rafters. Tank 13 is 250' in diameter, with a cone shape roof made of over 49,000 ft^2 of welded steel plates.[31] 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 13 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 13'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 13's roof was inspected (276.5 square feet (ft^2))[32] using the Automated Ultrasonic Testing (AUT) system. An inspection covering 276.5 ft^2 equates to only 0.6% of the roof. Only ten (10) measurements were made. Seven (7) concentrated on a single roof plate (Plate 115). Two other measurements were made on Plate 175, and one on Plate 116.[33]

A visual inspection of the roof structure was completed from the tank floor by the inspector. [34] The 24" nozzles were inspected using ultrasound.

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 7%[35] with a remaining roof plate thickness of 0.307". The 7% corrosion loss was computed using an original roof plate thickness of 0.331". The original roof plate thickness was 0.375" which makes the corrosion loss 18% not 7%.

The inspectors measured a maximum of 11% wall loss on the 24" roof nozzles.[36]

[31] 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 13 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.

[32] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 136.

[33] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 36.

[34] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.

[35] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 11 and 36.

[36] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 187.

7.4 Comparison to Prior Inspection Results: The 1998 internal inspection showed the Roof Plate 111 had the highest corrosion measured at 0.320” remaining thickness. No measurement was taken on Plate 111 (the thinnest roof plate measurement obtained in the last out-of-service measurement in 1998).

The 2004 external roof inspection collected 52 roof thickness measurements by ultrasonic technique, by sampling points along the roof lines in each compass direction. The thinnest roof plate measurement recorded was 0.306”.

The prior 2009 external roof inspection 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 0.292”, equating to a 22% roof plate corrosion loss from the original roof plate thickness of 0.375”. The roof plate with the highest corrosion rate measured in 2009 was not re-measured in the 2012 inspection.

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 (0.292”). 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.

7.6 Roof Summary: A summary of Tank 13’s roof design and inspection data is shown in the table below.

Tank 13 Roof Design and Inspection Data	Inspection Year	Measured Thickness
Roof Installed	1976	0.375”
AUT Inspection Data	1998	0.320”
AUT Inspection Data	2004	0.306”
AUT Inspection Data	2009	0.292”
AUT Inspection Data	2012	0.307”
Minimum required thickness for Tank 13’s roof considering Valdez snow loading		0.250”

8. Roof Support Column Inspection

8.1 Design Information: Tank 13's roof support column design includes 61, 24-inch diameter columns. The column design is made of 0.50" thick nominal members. The Tank 13 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 was used to examine each of the columns, with four (4) readings taken on each column on the north, south, east, and west faces. A visual inspection of the support column bases was completed by the inspectors.[37] Accessible areas of under support columns, near the areas that were re-padded, were inspected using Manual Ultrasonic Testing.

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.[38] The column thickness measurement (without coating) exceeded 0.500" for 60 of 61 columns, with only one column (#39) that had a reading on the north face of 0.498", less than 1% corrosion loss.

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 only 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. In general, the trend over that 14 years interval showed some increasing corrosion, with the exception of column #26 where the 1998 inspection measurements (0.513", 0.507", 0.509", and 0.509") were less than the 2012 measurements (0.523", 0.521", 0.523", and 0.520"). This difference isn't significant because even the 1998 measurements exceed the original design thickness of 0.500", but it is important for the inspectors to be aware of prior measurements and look at data trends.

9. Fire Foam System Inspection

9.1 Design Information: Tank 13 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.[39]

9.3 2012 Inspection Results and Repairs: The inspectors 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).[40] The largest wall loss measured (53%)[41] was found 56'7" downstream from the internal flange face connection. That section of pipe was originally 0.350" thick, and was measured to be 0.164" thick in 2012 (a corrosion loss of 0.186", approximately 53%).

[37] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.

[38] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 10 and 30-31.

[39] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.

[40] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 11 and 36.

[41] Note, the inspection report (p.33) incorrectly calculated this corrosion loss at 44%, but that was corrected in the summary table on page 11 to 53% which is correct.

Twenty one (21) measurements were made. Internal corrosion was found on all 21 measurements (2% to 53% corrosion loss). Seven (7) of the 21 measurements exceeded 30% wall loss.[42] No repairs were made. The inspectors report stated: "*No repairs were deemed necessary because of the significant amount of remaining wall*."[43] APSC's 2013 Engineering Report on the 2012 inspection concludes: "*The piping was determined by Integrity Management to be fit for service until the next internal inspection*." 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.

10. Sump Inspection

10.1 Design Information: Tank 13 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. [44]

10.3 2012 Inspection Results & Repairs: The inspectors measured a 10% wall loss on the circumferential band and approximately 1% wall loss on the sump walls. There was no damage to the sump requiring repair.[45]

The inspectors found the east diffuser wear pad on the sump floor was seeping crude oil from a void in the seal weld. The wear pad was removed causing, "*excessive mechanical damage (gouging) to the sump floor during the removal*"[46] The east diffuser wear pad was replaced with a larger pad to provide a larger overlay with the sump floor weld seam and the sump floor was repaired.

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 13 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. [47]

11.3 2012 Inspection Results & Repairs: The inspectors measured a maximum corrosion loss of 3% on the 36" Suction/Fill Line inside the tank.[48] 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.

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[42] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 125.
[43] Note, the inspection report (p.33) calculated this corrosion loss at 44%, but that was corrected in the summary table to 53%.
[44] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.
[45] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 12 and 57.
[46] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 14.
[47] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 7-8.
[48] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Pages 37.

12. Foundation Inspection

Tank 13'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.[49] The 2012 API 653 inspector found the 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.[50] 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 2004 external inspection report also recorded that the sealant at the bottom of the tank and the top of the concrete foundation is loose or missing, and that vegetation was growing around the perimeter of the tank.

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*."[51]

14. Cathodic Protection (CP) System

In 1998, a cathodic protection system was installed under Tank 13 and a new tank floor was installed.[52] Tank 13'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 13) 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 13 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

[49] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 38.

[50] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 38.

[51] Team Peak Alaska Report, prepared for APSC September 2012, on Tank 13's June 2012 inspection, Page 38.

[52] 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 13 CP system commissioning.

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 mountainside behind the tank farm provide wet soil beneath Tank 13 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 13.

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 13'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.[53]

An impressed current system uses a rectifier to convert alternating current (AC) (provided by the VMT power system) to direct current (DC). Rectifier[54] 54-DPS-13-1 supplies power to Tank 13's anode grid.[55] 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.[56] 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.[57]

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

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[53] 2002 TAPS Valdez Marine Terminal Cathodic Protection Survey, WO# 32000354-01, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., December 30, 2002.

[54] 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-13-1 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).

[55] 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.

[56] 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.

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

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 13, six (6) 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. 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, with three exceptions (reference cell #2 in Years 2002, 2006, and 2011). Please see Attachments No. 1, 2 and 3 to this report for a summary of the data.

Cathodic protection system data for 2012 was not available. Tank 13 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 13 from 41 test points in 1999 to 2008 to only nine (9) test points in 2009 to 2011. In 2010, PWSRCAC raised concern about the reduced number of test points. In 2013 and 2014, APSC resumed the higher testing frequency to 39 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} – 8^{th}), usually in approximately the same location each inspection (along the stairs). 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 collected only 10 measurements on three roof plates (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 internal inspections measured annular ring and roof corrosion that exceeded the measurements reported in 2012. It is possible that the 2012 inspector found the 2012 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 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 13, 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 13. Tank 13 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.

15.4 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 53% 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 53% corrosion loss measurement was taken. It will be important to understand the date the fire foam piping was installed in Tank 13, 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.

15.5 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.

15.6 Roof Support Corrosion Allowance. Tank 13's roof support column design includes 61, 24-inch diameter columns. The column design is made of 0.50" thick nominal members. The Tank 13 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.

15.7 Cathodic Protection System Operation. The cathodic protection system plays an important role in protecting Tank 13'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.

15.8 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 13	Crude Oil Tank No. 13
VMT	Valdez Marine Terminal
WFMT	Wet Fluorescent Magnetic Particle Testing

Attachment No. 1: Tank 13 Cathodic Protection System Testing (1999-2004)
Data Compiled by Harvey Consulting, LLC from data provided by APSC

	1999 Testing			2000 Testing			2001 Testing			2002 Testing			2003 Testing (June)			2003 Testing (July)*			2004 Testing		
	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarizati on (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met
Northeast Reference Cell Tube																					
10' measurement	-923		yes	**-760**	-307	yes	**-698**	-348	yes	-938		yes	**-688**	-337	yes	**-592**	-241	yes	-931		yes
20' measurement	**-832**	-446	yes	**-560**	-171	yes	**-635**	-334	yes	-947		yes	**-812**	-510	yes	**-609**	-307	yes	**-842**	-519	yes
30' measurement	-892		yes	**-648**	-147	yes	**-618**	-269	yes	-1039		yes	**-530**	-224	yes	**-456**	-150	yes	-974		yes
40' measurement	-863		yes	**-799**	-528	yes	-953		yes	-968		yes	**-619**	-421	yes	**-474**	-276	yes	**-769**	-517	yes
50' measurement	**-785**	-397	yes	**-675**	-416	yes	**-514**	-286	yes	-1003		yes	**-546**	-373	yes	**-513**	-340	yes	**-772**	-585	yes
60' measurement	-865		yes	**-695**	-427	yes	**-592**	-368	yes	**-828**	-660	yes	**-591**	-440	yes	**-530**	-379	yes	**-712**	-522	yes
70' measurement	-911		yes	**-707**	-452	yes	**-601**	-398	yes	**-748**	-564	yes	**-632**	-490	yes	**-626**	-484	yes	**-599**	-415	yes
80' measurement	-869		yes	**-693**	-430	yes	-922	-695	yes	-955		yes	**-569**	-421	yes	**-531**	-383	yes	**-583**	-403	yes
90' measurement	-778		yes	**-760**	-554	yes	**-713**	-509	yes	**-533**	-358	yes	**-395**	-232	yes	**-435**	-272	yes	**-515**	-351	yes
100' measurement	**-823**	-414	yes	-895		yes	**-638**	-395	yes	-963		yes	**-695**	-550	yes	**-635**	-490	yes	**-576**	-381	yes
110' measurement	-906		yes	**-703**	-437	yes	**-657**	-406	yes	-925		yes	**-667**	-536	yes	**-631**	-500	yes	-915	-760	yes
120' measurement	-885		yes	**-778**	-509	yes	**-723**	-515	yes	-897		yes	**-510**	-356	yes	**-530**	-376	yes	**-649**	-484	yes
130' measurement	-948		yes	-883		yes	no measurement		unknown	-1199		yes	**-815**	-650	yes	**-797**	-632	yes	**-551**	-377	yes
140' measurement	-942		yes	**-782**	-548	yes	no measurement		unknown	no measurement		unknown	**-785**	-672	yes	**-563**	-450	yes	**-622**	-469	yes
150' measurement	no measurement		unknown	no measurement		unknown	no measurement		unknown	no measurement		unknown	**-624**	-496	yes	**-519**	-391	yes	**-648**	-530	yes
South Reference Cell Tube																					
10' measurement	-862		yes	**-747**	-446	yes	**-617**	-327	yes	**-712**	-483	yes	**-804**	-527	yes	**-670**	-393	yes	**-793**	-455	yes
20' measurement	**-829**	-500	yes	**-653**	-401	yes	**-652**	-398	yes	**-790**	-597	yes	**-638**	-419	yes	**-574**	-355	yes	**-578**	-335	yes
30' measurement	-853		yes	**-588**	-360	yes	**-702**	-466	yes	-871		yes	**-787**	-585	yes	**-661**	-459	yes	**-823**	-574	yes
40' measurement	-857		yes	**-692**	-458	yes	**-703**	-476	yes	-855		yes	**-488**	-292	yes	**-449**	-253	yes	**-699**	-471	yes
50' measurement	-906		yes	**-768**	-530	yes	-926		yes	-918		yes	-862		yes	**-717**	-519	yes	**-835**	-583	yes
60' measurement	-893		yes	**-769**	-534	yes	**-788**	-568	yes	-870		yes	-891		yes	**-645**	-445	yes	**-801**	-586	yes
70' measurement	-886		yes	**-731**	-465	yes	**-671**	-435	yes	**-551**	-350	yes	**-629**	-441	yes	**-495**	-307	yes	**-777**	-569	yes
80' measurement	-872		yes	**-734**	-417	yes	-904		yes	**-669**	-450	yes	**-559**	-375	yes	**-444**	-260	yes	**-730**	-529	yes
90' measurement	-887		yes	**-768**	-409	yes	**-836**	-578	yes	**-718**	-521	yes	**-585**	-404	yes	**-520**	-339	yes	**-679**	-491	yes
100' measurement	-1064		yes	-907		yes	**-835**	-574	yes	-883		yes	-855	-646	yes	**-574**	-365	yes	**-825**	-636	yes
West Reference Cell Tube																					
10' measurement	-891		yes	**-722**	-465	yes	**-805**	-553	yes	**-757**	-567	yes	**-722**	-433	yes	**-606**	-317	yes	**-784**	-544	yes
20' measurement	**-806**	-529	yes	**-632**	-410	yes	**-677**	-451	yes	-981		yes	**-578**	-370	yes	**-476**	-268	yes	**-540**	-319	yes
30' measurement	-907		yes	**-749**	-529	yes	**-715**	-497	yes	**-826**	-681	yes	-869		yes	**-684**	-519	yes	**-774**	-585	yes
40' measurement	-859		yes	**-754**	-554	yes	**-775**	-566	yes	-860		yes	**-667**	-530	yes	**-528**	-391	yes	**-592**	-415	yes
50' measurement	-894		yes	**-567**	-387	yes	**-568**	-377	yes	**-493**	-395	yes	**-454**	-320	yes	**-442**	-308	yes	**-580**	-413	yes
60' measurement	-886		yes	**-542**	-382	yes	**-424**	-256	yes	**-463**	-369	yes	**-368**	-244	yes	**-353**	-229	yes	**-424**	-311	yes
70' measurement	-1044		yes	**-620**	-428	yes	**-414**	-221	yes	**-653**	-544	yes	**-467**	-327	yes	**-553**	-413	yes	**-590**	-453	yes
80' measurement	-990		yes	**-671**	-423	yes	**-560**	-342	yes	**-477**	-352	yes	**-384**	-227	yes	**-390**	-233	yes	**-392**	-209	yes
90' measurement	-1013		yes	-1022		yes	**-821**	-327	yes	**-562**	-405	yes	**-483**	-319	yes	**-441**	-277	yes	**-536**	-327	yes
100' measurement	-1031		yes	-892		yes	-858		yes	-942		yes	**-623**	-323	yes	**-577**	-277	yes	**-621**	-379	yes
Permanent Reference Cell																					
1	**-642**	-312	yes	**-573**	-393	yes	**-814**	-629	yes	**-724**	-562	yes	**-849**	-700	yes	**-665**	-516	yes	**-644**	-493	yes
2	**-494**	-201	yes	**-437**	-254	yes	**-312**	-156	yes	**-226**	-96	no	**-335**	-199	yes	**-299**	-163	yes	**-223**	-121	yes
3	-868		yes	**-775**	-534	yes	**-836**	-642	yes	**-781**	-628	yes	-924	-794	yes	**-742**	-612	yes	**-748**	-608	yes
4	**-835**	-457	yes	**-758**	-522	yes	**-734**	-537	yes	**-640**	-470	yes	**-605**	-458	yes	**-544**	-397	yes	**-590**	-448	yes
5	**-806**	-488	yes	**-714**	-515	yes	-859	-668	yes	**-766**	-595	yes	**-545**	-373	yes	**-673**	-501	yes	**-759**	-575	yes
6	-852		yes	**-774**	-567	yes	**-672**	-488	yes	**-649**	-486	yes	**-651**	-513	yes	**-664**	-526	yes	**-754**	-621	yes

Values in **Bold Blue Font** indicate 1/Off Test data that does not meet the -850 Mv NACE criteria; warrenting further assessment of whether it meets the 100 mV polarization criteria.

*Testing was completed twice in 2003 because the recitifer output decreased.

Attachment No. 2: Tank 13 Cathodic Protection System Testing (2005-2010)
Data Compiled by Harvey Consulting, LLC from data provided by APSC

	2005 Testing			2006 Testing			2007 Testing			2008 Testing			2009 Testing			2010 Testing		
	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met
Northeast Reference Cell Tube																		
10' measurement	**-612**	-194	yes	**-583**	-314	yes	**-798**	-517	yes	**-610**	-355	yes	**-513**	-252	yes	**-859**		yes
20' measurement	**-654**	-333	yes	-851		yes	-864		yes	**-708**	-431	yes	no measurement		unknown	no measurement		unknown
30' measurement	**-678**	-306	yes	**-616**	-307	yes	-966		yes	-897		yes	no measurement		unknown	no measurement		unknown
40' measurement	**-597**	-357	yes	**-762**	-581	yes	-1095		yes	-999		yes	no measurement		unknown	no measurement		unknown
50' measurement	**-622**	-366	yes	**-508**	-331	yes	**-521**	-355	yes	-1127		yes	no measurement		unknown	no measurement		unknown
60' measurement	**-458**	-304	yes	**-737**	-588	yes	**-639**	-494	yes	**-537**	-375	yes	no measurement		unknown	no measurement		unknown
70' measurement	**-455**	-292	yes	-1044		yes	-900		yes	-1074		yes	no measurement		unknown	no measurement		unknown
80' measurement	**-632**	-460	yes	**-549**	-411	yes	-880		yes	-1124		yes	no measurement		unknown	no measurement		unknown
90' measurement	**-560**	-437	yes	-1181		yes	**-489**	-329	yes	**-498**	-332	yes	no measurement		unknown	no measurement		unknown
100' measurement	**-699**	-548	yes	-1494		yes	-1154		yes	**-783**	-611	yes	no measurement		unknown	no measurement		unknown
110' measurement	**-685**	-538	yes	**-828**	-689	yes	**-638**	-493	yes	-1120		yes	no measurement		unknown	no measurement		unknown
120' measurement	**-527**	-385	yes	-1108		yes	-960		yes	**-753**	-581	yes	no measurement		unknown	no measurement		unknown
130' measurement	**-529**	-403	yes	**-843**	-652	yes	-1515		yes	-1200		yes	no measurement		unknown	no measurement		unknown
140' measurement	**-507**	-368	yes	-1318		yes	**-732**	-583	yes	**-791**	-623	yes	no measurement		unknown	no measurement		unknown
150' measurement	**-568**	-450	yes	-1196		yes	-969		yes	**-727**	-567	yes	no measurement		unknown	no measurement		unknown
South Reference Cell Tube																		
10' measurement	**-633**	-330	yes	-1479		yes	**-763**	-498	yes	**-842**	-597	yes	**-645**	-452	yes	**-856**		yes
20' measurement	**-513**	-245	yes	-1217		yes	-878		yes	**-581**	-342	yes	no measurement		unknown	no measurement		unknown
30' measurement	**-645**	-397	yes	-1167		yes	-1043		yes	**-578**	-393	yes	no measurement		unknown	no measurement		unknown
40' measurement	**-529**	-274	yes	-901		yes	**-494**	-317	yes	-875		yes	no measurement		unknown	no measurement		unknown
50' measurement	**-659**	-429	yes	-1133		yes	-1013		yes	-935		yes	no measurement		unknown	no measurement		unknown
60' measurement	**-640**	-444	yes	**-630**	-424	yes	-833		yes	-978		yes	no measurement		unknown	no measurement		unknown
70' measurement	**-615**	-409	yes	**-626**	-419	yes	**-471**	-282	yes	**-614**	-407	yes	no measurement		unknown	no measurement		unknown
80' measurement	**-625**	-450	yes	**-726**		yes	-1002		yes	**-542**	-369	yes	no measurement		unknown	no measurement		unknown
90' measurement	**-653**	-478	yes	**-681**		yes	**-455**	-284	yes	-1055		yes	no measurement		unknown	no measurement		unknown
100' measurement	**-624**	-473	yes	**-867**		yes	-983		yes	-877		yes	no measurement		unknown	no measurement		unknown
West Reference Cell Tube																		
10' measurement	**-607**	-341	yes	**-764**	-500	yes	-988		yes	-1012		yes	**-708**	-518	yes	**-977**		yes
20' measurement	**-625**	-371	yes	**-592**	-258	yes	-918		yes	**-834**	-644	yes	no measurement		unknown	no measurement		unknown
30' measurement	**-574**	-361	yes	-861		yes	-999		yes	-987		yes	no measurement		unknown	no measurement		unknown
40' measurement	**-553**	-401	yes	**-539**	-381	yes	**-830**	-679	yes	**-498**	-363	yes	no measurement		unknown	no measurement		unknown
50' measurement	**-492**	-339	yes	**-473**	-313	yes	**-438**	-315	yes	**-435**	-330	yes	no measurement		unknown	no measurement		unknown
60' measurement	**-423**	-313	yes	**-355**	-232	yes	**-419**	-289	yes	**-447**	-314	yes	no measurement		unknown	no measurement		unknown
70' measurement	**-365**	-248	yes	-893		yes	**-353**	-217	yes	**-375**	-222	yes	no measurement		unknown	no measurement		unknown
80' measurement	**-434**	-284	yes	**-634**	-470	yes	**-407**	-254	yes	**-422**	-422	yes	no measurement		unknown	no measurement		unknown
90' measurement	**-434**	-268	yes	**-539**	-363	yes	**-519**	-324	yes	**-443**	-271	yes	no measurement		unknown	no measurement		unknown
100' measurement	**-498**	-217	yes	**-660**	-311	yes	**-659**	-324	yes	**-758**	-405	yes	no measurement		unknown	no measurement		unknown
Permanent Reference Cell																		
1	**-718**	-567	yes	-812		yes	-866		yes	-952		yes	**-668**	-541	yes	**-586**	713	yes
2	**-238**	-155	yes	**-130**	-37	no	**-210**	-124	yes	**-196**	-111	yes	**-209**	-148	yes	**-349**	-288	yes
3	-870		yes	-922		yes	-981		yes	-1056		yes	**-764**	-656	yes	**-662**	-554	yes
4	**-530**	-411	yes	**-607**	-487	yes	**-671**	-571	yes	**-524**	-473	yes	**-575**	-497	yes	**-578**	-500	yes
5	**-785**	-629	yes	-885		yes	-912		yes	-1001		yes	**-750**	-604	yes	-911		yes
6	-923		yes	-978		yes	-904		yes	-1045		yes	no measurement		unknown	-1000		yes

Values in **Bold Blue Font** indicate 1/Off Test data that does not meet the -850 Mv NACE criteria; warrenting further assessment of whether it meets the 100 mV polarization criteria.

Attachment No. 3: Tank 13 Cathodic Protection System Testing (2011-2014)

Data Compiled by Harvey Consulting, LLC from data provided by APSC

	2011 Testing			2012 Testing*			2013 Testing			2014 Testing		
	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met	I/Off 850 OFF (mV)	100mV Polarization (mV)	Criteria Met
Northeast Reference Cell Tube												
10' measurement	-1119	-376	yes	no measurement		unknown	**-541**	-287	yes	**-750**	-496	yes
20' measurement	no measurement		unknown	no measurement		unknown	**-434**	-193	yes	**-814**	-573	yes
30' measurement	no measurement		unknown	no measurement		unknown	**-489**	-233	yes	**-703**	-450	yes
40' measurement	no measurement		unknown	no measurement		unknown	**-371**	-197	yes	-901	-727	yes
50' measurement	no measurement		unknown	no measurement		unknown	**-349**	-199	yes	**-472**	-322	yes
60' measurement	no measurement		unknown	no measurement		unknown	**-465**	-296	yes	**-626**	-457	yes
70' measurement	no measurement		unknown	no measurement		unknown	**-494**	-354	yes	**-518**	-378	yes
80' measurement	no measurement		unknown	no measurement		unknown	**-491**	-377	yes	**-483**	-369	yes
90' measurement	no measurement		unknown	no measurement		unknown	**-447**	-287	yes	**-466**	-306	yes
100' measurement	no measurement		unknown	no measurement		unknown	**-408**	-272	yes	**-531**	-395	yes
110' measurement	no measurement		unknown	no measurement		unknown	**-456**	-330	yes	**-426**	-300	yes
120' measurement	no measurement		unknown	no measurement		unknown	**-385**	-241	yes	**-379**	-235	yes
130' measurement	no measurement		unknown	no measurement		unknown	no measurement		unknown	no measurement		unknown
140' measurement	no measurement		unknown	no measurement		unknown	no measurement		unknown	no measurement		unknown
150' measurement	no measurement		unknown	no measurement		unknown	no measurement		unknown	no measurement		unknown
South Reference Cell Tube												
10' measurement	-1160	-255	yes	no measurement		unknown	**-538**	-336	yes	**-522**	-320	yes
20' measurement	no measurement		unknown	no measurement		unknown	**-431**	-273	yes	**-672**	-514	yes
30' measurement	no measurement		unknown	no measurement		unknown	**-572**	-411	yes	**-770**	-609	yes
40' measurement	no measurement		unknown	no measurement		unknown	**-528**	-369	yes	-851	-692	yes
50' measurement	no measurement		unknown	no measurement		unknown	**-707**	-544	yes	**-583**	-420	yes
60' measurement	no measurement		unknown	no measurement		unknown	**-685**	-532	yes	**-650**	-497	yes
70' measurement	no measurement		unknown	no measurement		unknown	**-572**	-406	yes	**-589**	-423	yes
80' measurement	no measurement		unknown	no measurement		unknown	**-520**	-347	yes	**-701**	-528	yes
90' measurement	no measurement		unknown	no measurement		unknown	**-420**	-261	yes	**-618**	-459	yes
100' measurement	no measurement		unknown	no measurement		unknown	**-485**	-336	yes	**-538**	-389	yes
West Reference Cell Tube												
10' measurement	**-729**	-264	yes	no measurement		unknown	**-619**	-412	yes	**-801**	-594	yes
20' measurement	no measurement		unknown	no measurement		unknown	**-431**	-250	yes	**-529**	-348	yes
30' measurement	no measurement		unknown	no measurement		unknown	**-308**	-147	yes	**-398**	-237	yes
40' measurement	no measurement		unknown	no measurement		unknown	**-358**	-210	yes	**-452**	-304	yes
50' measurement	no measurement		unknown	no measurement		unknown	**-420**	-271	yes	**-406**	-257	yes
60' measurement	no measurement		unknown	no measurement		unknown	**-358**	-190	yes	**-391**	-223	yes
70' measurement	no measurement		unknown	no measurement		unknown	**-380**	-208	yes	**-454**	-282	yes
80' measurement	no measurement		unknown	no measurement		unknown	**-515**	-306	yes	**-389**	-180	yes
90' measurement	no measurement		unknown	no measurement		unknown	**-846**	-584	yes	**-429**	-167	yes
100' measurement	no measurement		unknown	no measurement		unknown	**-643**	-274	yes	**-507**	-138	yes
Permanent Reference Cell												
1	-1092	-147	yes	no measurement		unknown	**-501**	-368	yes	**-690**	-557	yes
2	**-250**	**-50**	**no**	no measurement		unknown	**-283**	-197	yes	**-285**	-199	yes
3	-1173	-114	yes	no measurement		unknown	**-467**	-351	yes	**-680**	-564	yes
4	-855	-85	yes	no measurement		unknown	**-264**	-297	yes	**-376**	-409	yes
5	-1033	-163	yes	no measurement		unknown	**-582**	-445	yes	**-754**	-617	yes
6	-1015	-463	yes	no measurement		unknown	**-555**	-439	yes	**-549**	-433	yes
Tank Center	no measurement		unknown	no measurement		unknown	**-370**	-270	yes	**-550**	-450	yes

Values in **Bold Blue Font** indicate 1/Off Test data that does not meet the -850 Mv NACE criteria; warrenting further assessment of whether it meets the 100 mV polarization criteria.

* 1/27/15 Email from Barry Roberts (APSC) to Linda Swiss (PWSRCAC) states no data was collected in 2012 because the CP system was out of service during the 2012 Tank 13 inspection.