REDACTED FINAL REPORT
Crude Oil Storage Tank 8 Maintenance Review
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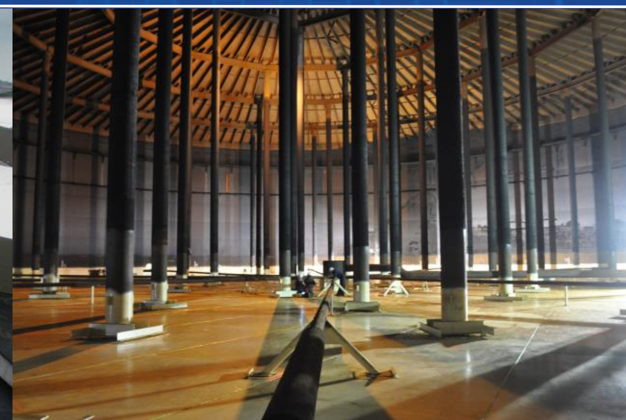

Report Prepared for:

PRINCE WILLIAM SOUND
RCAC
REGIONAL CITIZENS' ADVISORY COUNCIL

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The opinions expressed in this PWSRCAC commissioned report are not necessarily those of PWSRCAC.

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ACRONYMNS & ABBREVIATIONS

AAC – Alaska Administrative Code

ADEC – Alaska Department of Environmental Conservation

API – American Petroleum Institute

APSC – Alyeska Pipeline Service Company

ASNT- American Society of Nondestructive Testing

AST – Aboveground Storage Tanks

CP – Cathodic Protection

ETF – East Tank Farm

FDN - Foundation

IM – Integrity Management

IR – Current (I) times Resistance (R) or voltage. Refers to voltage gradients in soils due to applied CP.

IRF – IR-free or Instant Off Readings

MMO - Mixed Metal Oxide

MP – Monitoring Procedure

MPY – Mils-per-year

NACE – National Association of Corrosion Engineers

NDE – Non-Destructive Evaluation

NOAA – National Oceanic and Atmospheric Administration

PWSRCAC - Prince William Sound Regional Citizens' Advisory Council

TAPS – Trans Alaska Pipeline System

TK - Tank

VMT – Valdez Marine Terminal

WTF – West Tank Farm

1.0 EXECUTIVE SUMMARY

In May 2020, Prince William Sound Regional Citizen's Advisory Council (PWSRCAC) tasked Taku Engineering (Taku) with reviewing documents associated with Tank 8 at the Alyeska Pipeline Service Company (APSC) Valdez Marine Terminal (VMT). The intent was to identify opportunities for reducing the risks of a leak associated with the VMT tanks.

Constructed in 1976, Tank 8 is a 250-foot diameter, 500,000-barrel, welded steel, crude oil storage tank located in the VMT's East Tank Farm (ETF). In 1995, the tank was removed from service and a new floor with a sub-floor cathodic protection (CP) system was installed. The tank was again removed from service for internal inspections in 2007 and 2019. After the 2019 out-of-service inspection, minor repairs were completed, and the tank was prepared to be coated and returned to service. An individual within APSC noted concerns with the inspection and initiated a follow-up inspection that identified more significant soil-side corrosion damage than had been discovered during the first inspection. At that point, APSC made the decision to replace the tank floor and CP system.

Problems associated with the COVID-19 pandemic prompted the decision to complete minor floor repairs in 2020, and return the tank to service until 2023, at which time it will be removed from service and the floor and CP system will be replaced.

This study considered historic inspection and maintenance records for APSC's tanks. It has resulted in the development of a number of findings and recommendations. Detailed findings and recommendations are provided in Sections 4 & 5 of this document. Summarization of these general findings and recommendations are discussed below:

2019 API 653 INSPECTION

APSC's inspection and maintenance efforts for Tank 8 include periodic inspections in accordance with American Petroleum Institute - Standard 653 (API 653), coatings (internally on the tank floor, externally on the tank shell, and externally on the tank roof), and cathodic protection of the tank floor (externally).

The initial 2019 API 653 Out-of-Service inspection completed on Tank 8 failed to identify a significant amount of the corrosion present in Tank 8. These oversights suggest that there were shortcomings in the execution of that inspection. During the course of this investigation, we requested documents pertaining to the first inspection. APSC has not substantially replied to this request.

APSC indicated that they did conduct an internal investigation into the causes of the initial inspection failures. We requested copies of those findings. APSC has refused to comply with that request. We are unable to draw concrete conclusions and recommendations regarding the cause (or causes) of the inspection failures without the documentation that was requested.

APSC should ensure that the level of quality control on their non-destructive evaluation (NDE) inspections is appropriate and aligns with the structure of the contract utilized for those inspections. An NDE contract that is bundled with a construction contract may need more oversite than an NDE effort completed by an independent third-party contractor.

2020 API 653 INSPECTION/RETURN-TO-SERVICE

Due to the failure of the initial 2019 API 653 inspection to identify significant amounts of corrosion on Tank 8, a second inspection was conducted and completed by 2020. The 2020 API 653 Out-of-Service inspection that was completed on Tank 8, appears to have been conducted in a competent and professional manner. The second API

653 inspection was completed by qualified individuals. The corrosion rate calculations and assumptions were completed in a thorough and conservative manner. Tank 8 has a very low risk of leaking from a corrosion failure during the current 4-year service interval, between now and 2023 when the tank's floor and CP system are scheduled for replacement.

The 2020 API 653 report was silent regarding tank settlement. Aboveground storage tanks sometimes shift or settle which can cause significant stresses on the tank structure. APSC should ensure that a settlement assessment was completed in the tank during the outage, especially in light of the November 2018 earthquake.

SUB-FLOOR WATER ACCUMULATION

APSC has not maintained the seals between the perimeter of the tank floors and the tank concrete support foundations (ringwalls). This is allowing rainwater to migrate beneath the floor and into the area between the steel floorplate and the secondary containment liner. If the secondary containment liner is intact, water will accumulate between the secondary containment liner and the floorplate, increasing the likelihood of corrosion and increasing the risk of damaging the tank near the sump. The sump is the lowest point in the tank floor. Drainage systems that were installed beneath some of the tank floors will reduce this risk but were installed at an elevation that is too high to fully alleviate it.

APSC should drain as much water as possible from beneath the tanks through the available drainage piping and CP monitoring tubes. They should replace and maintain the ringwall/floorplate seals to prevent further water intrusion beneath the floors of storage tanks at the VMT.

2016-2018 CATHODIC PROTECTION (CP) DATA

The 2016-2018 Tank 8 cathodic protection data provided by APSC indicated that the tank floor was well protected from corrosion. However, the tank floor is corroding at a relatively high rate. The fact that the CP readings indicated that the floor was protected, but the floor was actively corroding, suggests that there may be problems associated with the CP data collection and reporting.

The 2016-2018 CP system testing data reported by APSC is not valid. It was not collected in accordance with industry standards, nor APSC's internal maintenance procedures. If the CP system were actually working properly, as the 2016-2018 data indicates, the corrosion rates measured on Tank 8's floor during the 2019/2020 API 653 inspection should have been significantly lower. However, the 2016-2018 CP testing data does not represent the actual conditions beneath Tank 8's floor and provides a false sense of security that the tank is protected from bottom-side corrosion.

APSC should ensure that the CP data that they collect is valid by adhering to the requirements of their own, internal procedures, State and Federal regulations, and accepted industry standards.

CATHODIC PROTECTION SYSTEM DESIGN

The existing CP system design does not provide a system that is easy to balance and adjust, making it difficult to protect the perimeter of Tank 8's floor. Any new CP systems designed should provide the means to balance and adjust the current across all areas of the tank floor.

TANK SECONDARY CONTAINMENT LINERS

The seals between the perimeter floorplates and concrete ringwalls have not been maintained on any of the VMT crude storage tanks. Therefore, it is highly probable that water is migrating between the steel floorplate and secondary containment liners on all of the crude storage tanks at the VMT. However, water buildup beneath the floor has always been more prevalent on some of the tanks. This suggests that the secondary containment liners beneath some of the tanks are leaking. APSC should institute a comprehensive assessment of the integrity of the secondary containment liners beneath all of the VMT crude storage tanks.

2.0 INTRODUCTION

Tank 8 at the Valdez Marine Terminal (VMT) is one of the 14 crude oil storage tanks that make up the VMT's East Tank Farm (ETF). Four additional tanks are located in the West Tank Farm (WTF). However, the West Tank Farm was removed from service in the early 2000s. The general VMT layout is shown below in Figure 1.

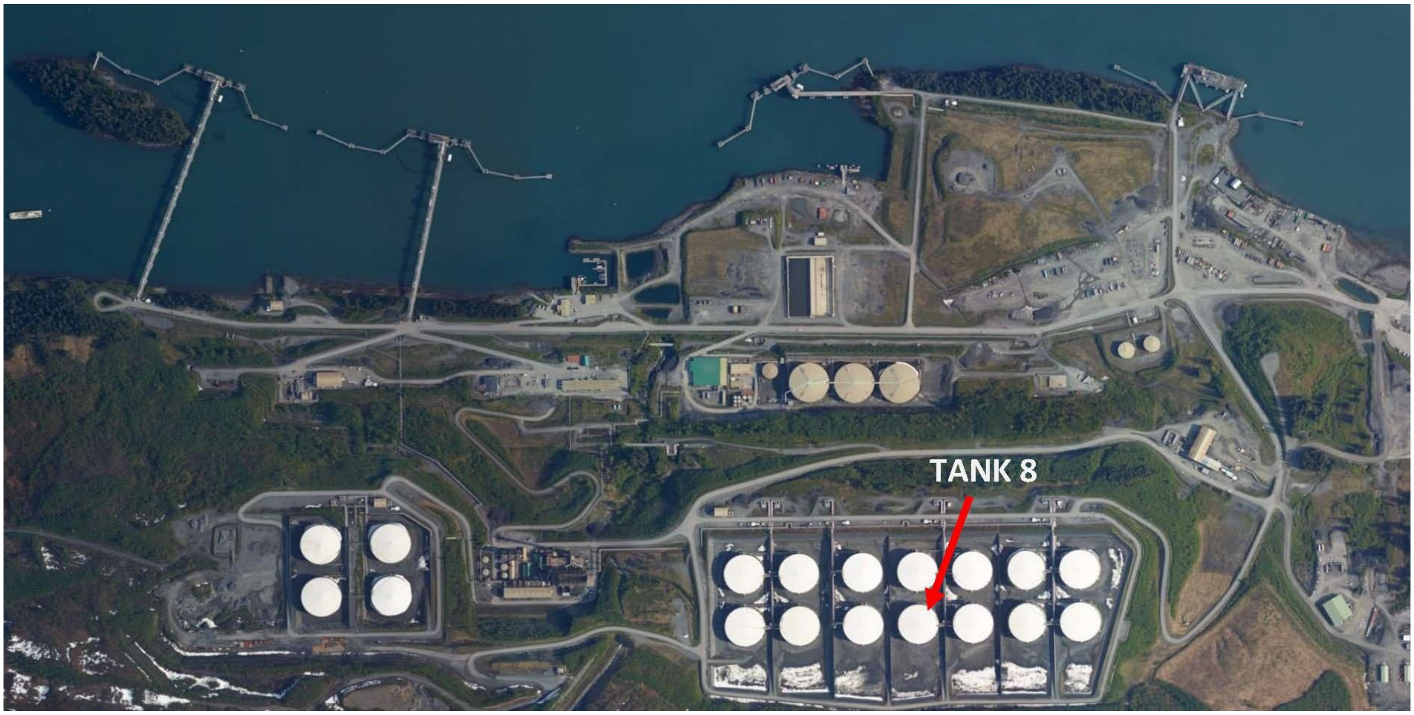

Figure 1 - VMT Aerial Photo (photo courtesy of NOAA)

All 14 ETF tanks are 250 feet in diameter, 62 feet high, welded steel, crude storage tanks built to API Standard 650. They were designed and erected by Chicago Bridge and Iron in 1976. The ETF tanks were constructed on concrete ringwalls with subsurface secondary containment liners and oiled sand bedding. The sketch in Figure 2 shows the general layout and typical components of a VMT crude storage tank.

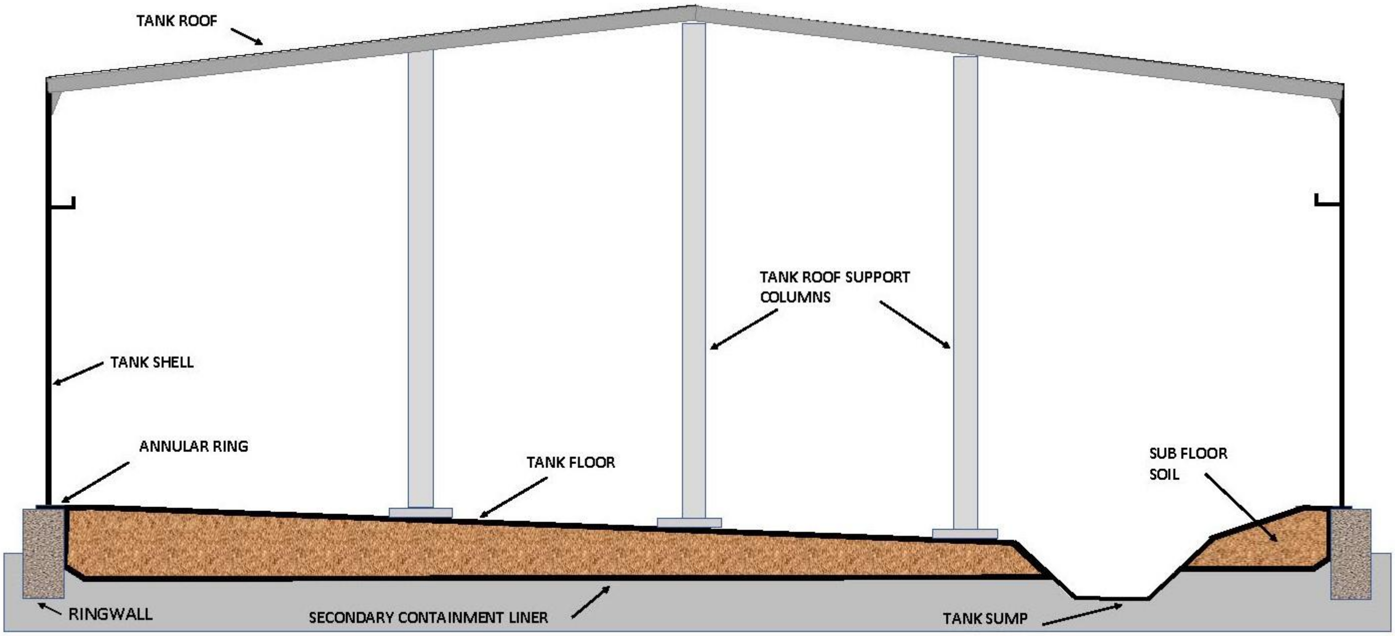

Figure 2 - Typical VMT Tank Configuration

The 1991 discovery of soil-side corrosion in the tank floors prompted APSC to systematically replace the tank floors and install sub-floor CP systems on all ETF tanks between the years 1991 and 1998. The initial CP system installed on Tank 5 in 1991 consisted of mixed metal oxide rod anodes. After the Tank 5 floor replacement, all other tanks were fitted with mixed metal oxide (MMO) grid cathodic protection systems which included monitoring tubes and/or permanent reference cells for collection of tank-to-soil potential measurements. The Tank 5 CP system was later replaced with a grid CP system in 2002.

The floorplates on Tank 8 were removed and replaced in 1995. The original oiled sand bedding was excavated and clean bedding, an MMO grid CP system, and new floorplates were installed in the tank. The existing annular (perimeter) plates remained in place.

Tank 8 was removed from service for internal inspection in 2007 and 2019. After the 2019 out-of-service inspection, minor repairs were completed on the tank floor and the tank was prepared to be coated and returned to service (Figure 3). A follow-up inspection, prompted by one of APSC's engineers, resulted in the discovery of more than 160 additional locations of corrosion that had been missed during the first inspection. At that point, the decision was made to replace the tank floor and CP system. Due to issues arising from the COVID-19 pandemic in 2020, the decision was made to complete minor repairs on Tank 8 and return it to service until 2023. At that time, APSC plans to remove the tank from service and replace the tank floor and CP system.

Figure 3 - Tank 8 During 2019 Out-of-Service Inspection (photo courtesy of Austin Love)

3.0 FINDINGS AND DISCUSSION

3.1 INITIAL 2019 API 653 INSPECTION

Taku requested data and findings from the initial API 653 out of service inspection completed on Tank 8 in 2019. APSC provided data in November of 2020 that included sketches of 14 tank bottom plates similar to the one of Plate 8 shown below in Figure 4. Similar data was provided for plates 10, 11, 18, 30, 31, 84, 100, 101, 136, 191, 207, 213, and 238. Absent proper documentation and clarification from APSC, it is assumed that this data originated from the first API 653 inspection conducted on Tank 8 in 2019.

FIGURE REDACTED AS PER APSC REQUEST

Figure 4 - Crude Tank 8 Plate 8 Corrosion Data

These sketches appear to present the locations and remaining wall thickness of corrosion identified in Tank 8 during the first inspection. However, there are several issues associated with this data:

- The sketches do not indicate where the data is from (i.e., Tank 8) or when it was collected.
- It is assumed that the data provided is the remaining wall thickness. However, that is not noted.
- There is no indication of who collected the data and whether they have the proper credentials.
- It is not signed and dated by a certified inspector.

This data should have been treated as quality data and properly documented and signed by the inspector.

Taku and PWSRCAC made numerous requests for information regarding the problems that occurred with the first (2019) API 653 inspection of Tank 8. Requests for specifics on the management systems in place to prevent tank inspection shortcomings were denied except for statements that their management system "worked as intended" and that the built-in system checks caught the shortcomings. This contradicts information from personnel inside APSC which suggested that an employee not directly involved with the tank project stepped in to identify the inspection shortcomings. However, APSC's refusal to provide documentation of their process and internal investigation made it impossible to verify information received from other sources.

Although no documents were received pertaining to the causes of the failures incurred in the original inspection, we have ascertained that a different contracting approach was utilized at the onset of this project. Rather than maintaining a 3rd party independent NDE contractor as has been the past practice, this approach rolled the responsibilities for the NDE inspection under the repair contractor. This should have prompted APSC to modify their quality control requirements for the inspection to reflect the lack of independent 3rd party oversight. No documentation was provided by APSC to ascertain if that was done or not.

3.2 2020 RETURN-TO-SERVICE

After the initial inspection, minor repairs were completed, and Tank 8 was prepared to be coated and returned to service. APSC personnel noted discrepancies in the original tank inspection findings and initiated a follow-on inspection which identified much more significant corrosion damage.

After that second inspection, APSC decided to replace the tank floor and the sub-floor cathodic protection system. However, due to difficulties arising from the COVID-19 pandemic in 2020, the decision was made to make minor repairs and return the tank to temporary service until 2023, at which time Tank 8's floor and CP system will be replaced.

The inspector of record for the second API 653 inspection and report was Vinnie Szymkowiak, PE. Mr. Szymkowiak is a licensed Civil Engineer in good standing with the State of Alaska (AEL C 10831 Expires 12/31/21). He also maintains a current API 653 Inspector certification that is in good standing (Certification # 93650 Expires 1/31/23).

A check of the credentials of the NDE inspectors that collected the second set of data on Tank 8 indicates that they all maintain current American Society of Nondestructive Testing (ASNT) or the inspection company's internal inspector credentials.

During the API 653 inspection, the tank shell, roof, columns, floorplate, and appurtenances were inspected. All floorplate thinning that had less than 180-mils (1 mil is equal to 1/1000th-inch) remaining was repaired by overlaying the surface with steel repair patches. Repair coatings were applied to the patch repair areas.

The Tank 8 floorplate is comprised of ¼-inch (250-mil) steel plate. The top surface is coated, and no topside corrosion was reported during the 2019/2020 internal inspection. After the 2020 repairs, the minimum remaining floorplate should be no less than 180-mils thick. Figure 5 shows how a cross section of the thinnest remaining (unrepaired) floor in Tank 8 might appear.

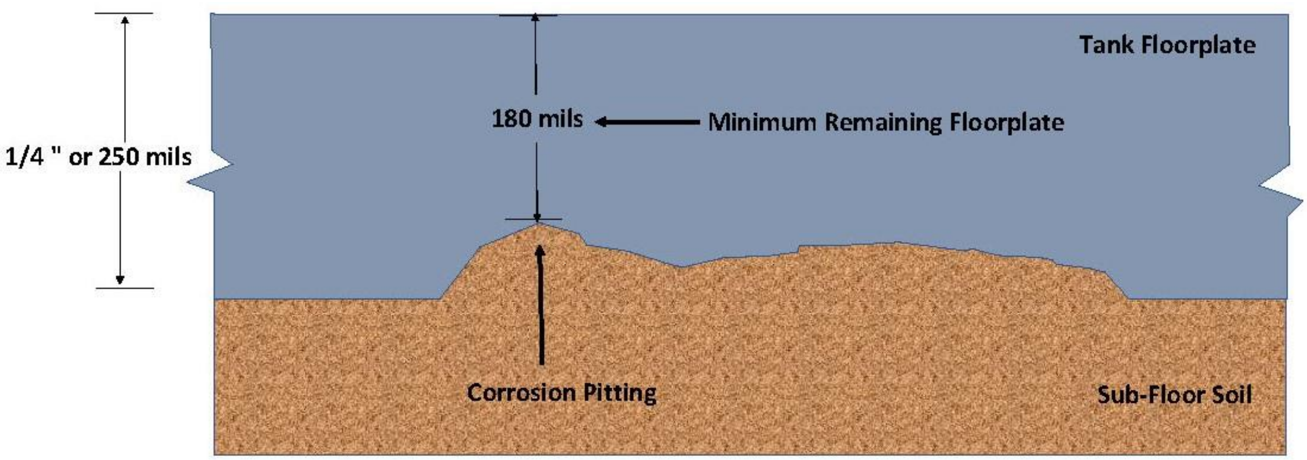

Figure 5 - Minimum Remaining Floorplate After 2019/2020 Repairs

The code requires that the floor still have a minimum of 100-mils of thickness remaining at the end of the planned service interval. That left APSC's engineers an 80-mil corrosion allowance to bridge the 4-year period between the inspection (2019) and removal from service again (2023). APSC used a corrosion rate of 20-mils per year as justification to bridge the 4-year service interval.

The actual corrosion rate experienced on the tank floor is closer to 11 mils-per year. The red dotted line in Figure 6 depicts the probable deepest pitting in the floorplate that will exist in 2023 (approximately 140-mils remaining wall thickness). The beige area represents the 100-mil minimum allowable floorplate thickness after the service interval.

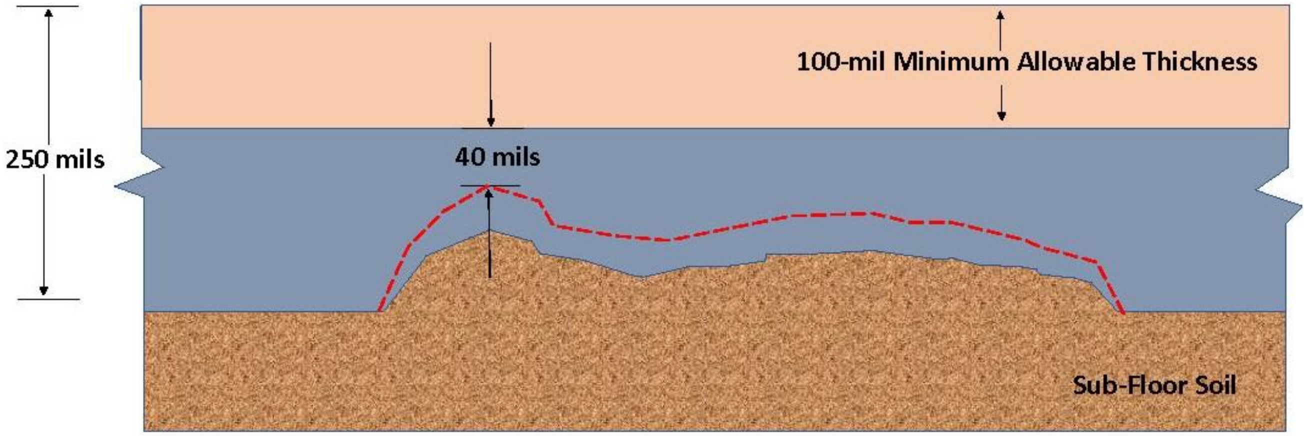

Figure 6 - Predicted Minimum Remaining Floorplate in 2023

APSC's approach to the 2020 return-to-service is relatively conservative. The assumed corrosion rate of the service interval calculations is significantly higher than the measured rate. There is very little risk of a corrosion failure from Tank 8 before the tank is removed from service again in 2023.

3.3 SUB-FLOOR WATER ACCUMULATION

Figure 7 shows a cutaway sketch of the Tank 8 foundation and subfloor layout. The Tank 8 shell (and all of the VMT crude tanks) rests on a concrete ringwall. The floorplate slopes down from the ringwall to the tank sump. The elevation of the perimeter floorplate is 3 feet, 7 inches above the elevation of the bottom of the sump. As shown in the sketch, there are roof support columns in relatively close proximity to the tank sump.

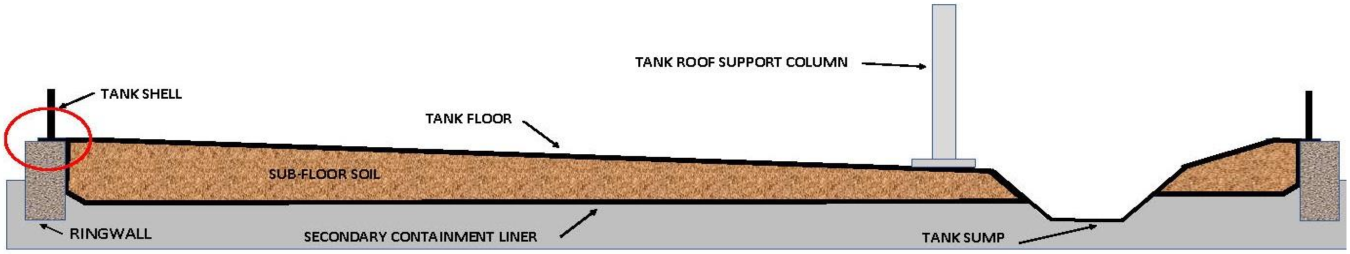

Figure 7 – Crude Tank Foundation and Subfloor Layout

Figure 8 represents an enlarged section view of the area in the red circle from Figure 7. The tank annular plate extension (or floorplate extension) rests directly on top of the concrete ringwall. The floorplate extension is not sealed to the concrete ringwall. Any rainwater running down the side of the tank can collect on the top of the ringwall and either run off the outer diameter of the foundation or seep under the annular plate extension and into the soils between the floorplate and secondary containment liner. This can exacerbate corrosion of the tank

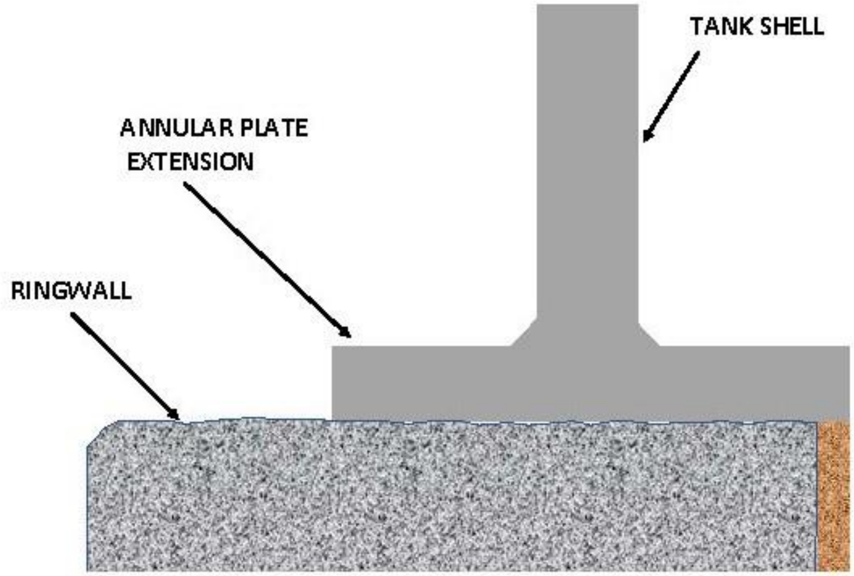

Figure 8 - Annular Plate Extension (No Seal)

floor and potentially lead to buoyancy forces pushing up on the tank floor and damaging it and/or the tank roof column supports – which is discussed in detail later.

Most operators seal between the annular plate extension and the concrete ringwall to prevent rainwater from migrating beneath the tank and increasing the risk of corrosion (shown in Figure 9). Operators typically use a flexible industrial grout to seal this joint in the manner shown below. Differential movement between the steel annular plate extension and the concrete ringwall may damage the seal so it requires frequent inspection and repair. In the 1980s APSC deemed that the seals were not critical and made the decision to allow them to degrade rather than to incur the continued cost to maintain them.

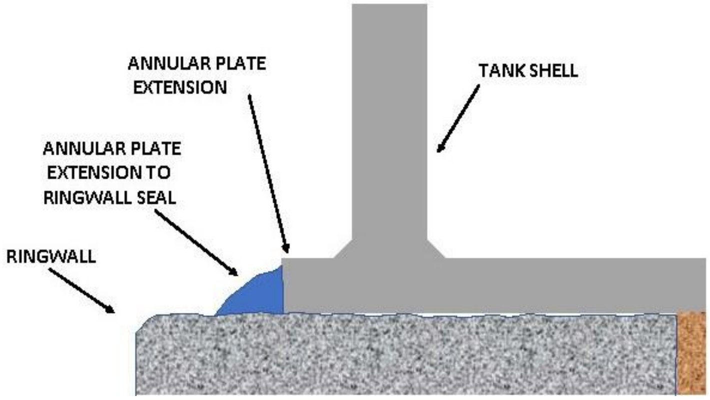

Figure 9 – Annular Plate Extension (Sealed)

The seals between the VMT tank annular plate extensions and the concrete ringwalls are still not maintained. Figure 10 is a photo depicting the condition of the Tank 8 annular plate extension/ringwall seal in 2019-2020. It is obvious from the photo that the seal has failed and is no longer preventing water from seeping beneath the tank floor.

Figure 10 - Tank 8 Ringwall/Annular Plate Seal

Rather than preventing water from seeping beneath the tank floor, the cracked seals may be exacerbating the water migration into that area. Figure 11 depicts a section of the ringwall/annular plate with a cracked seal. The presence of a crack in that joint forms a gap that may funnel more rainwater beneath the floor than would be caused by the lack of any seal.

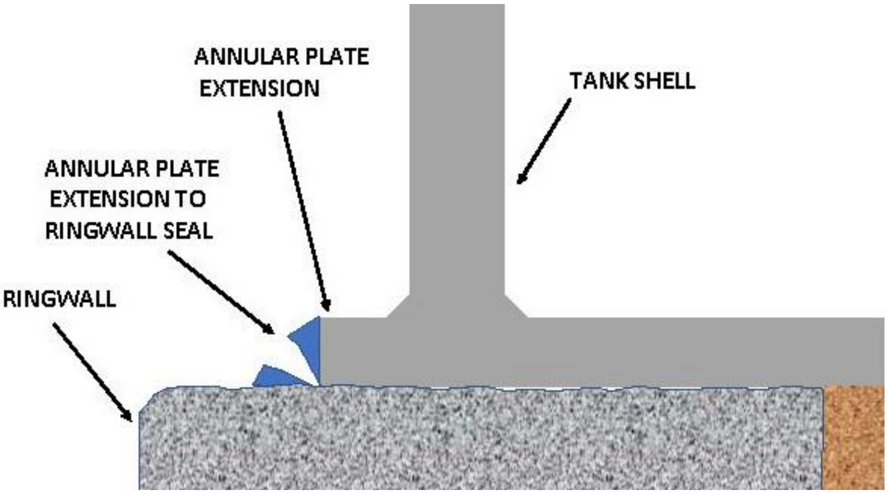

Figure 11 – Cracked Ringwall/Annular Plate Seal

Valdez gets an average of 70 inches of rain each year. Each tank roof is comprised of more than an acre of steel surface. All of the water falls on that surface, runs down the shell and onto the ringwall. If only 5% of the rainwater migrates beneath the floor, and the secondary containment liner is fully intact, the soils between the floor and secondary containment liner will be fully saturated in less than 1.5 years. These tanks are being placed in service for 10-20 years between inspections. Without ringwall seals, the soils beneath the floorplate will be saturated for the vast majority of the period they are in service.

Water-saturated soils beneath the crude tanks increase the risk of bottomside corrosion and impart buoyant (upward) forces on the tank sump and surrounding floorplate. When the tank is fully emptied of oil, these forces can cause the sump to float and be displaced vertically (Figure 12). There are four roof support columns in relatively close proximity to the sump. Any upward motion of the sump can cause high stresses on the adjacent columns, risking damage to the floor or column footing.

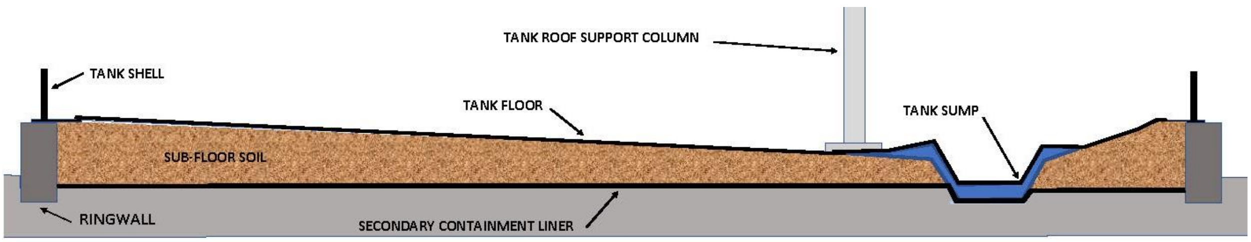

Figure 12 – Tank Sump Flotation

In 2019, Taku received a call from an individual in APSC who was concerned about floorplate distortions near columns adjacent to the sump. Photographs were requested from APSC of the as-found condition of each of the adjacent column bases and repads. Those were not received.

On some of the crude storage tanks, APSC installed subfloor drain piping between the tank floor and secondary containment liner (Figure 13). We have not received a record of exactly which tanks have that drainage system. However, the drain piping was installed at a level that is significantly higher than the bottom of the tank sump. While the drain piping will reduce the buoyant forces acting on the sump, it will not totally alleviate those forces.

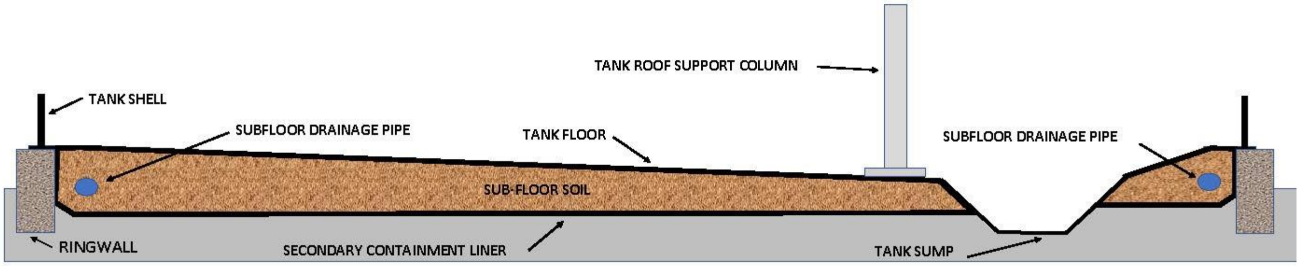

Figure 13 – Subfloor Drainage System Location

3.4 BOTTOMSIDE CATHODIC PROTECTION MONITORING

The APSC crude oil storage tank floors were not originally protected from soil side corrosion and experienced significant soil-side corrosion during the first 15-20 years that they were in service. In the 1990s and early 2000s, the crude tank floors were replaced, and subfloor grid type cathodic protection (CP) systems were installed between the new floorplate and the tank's secondary containment liner (similar to the shown in Figure 14).

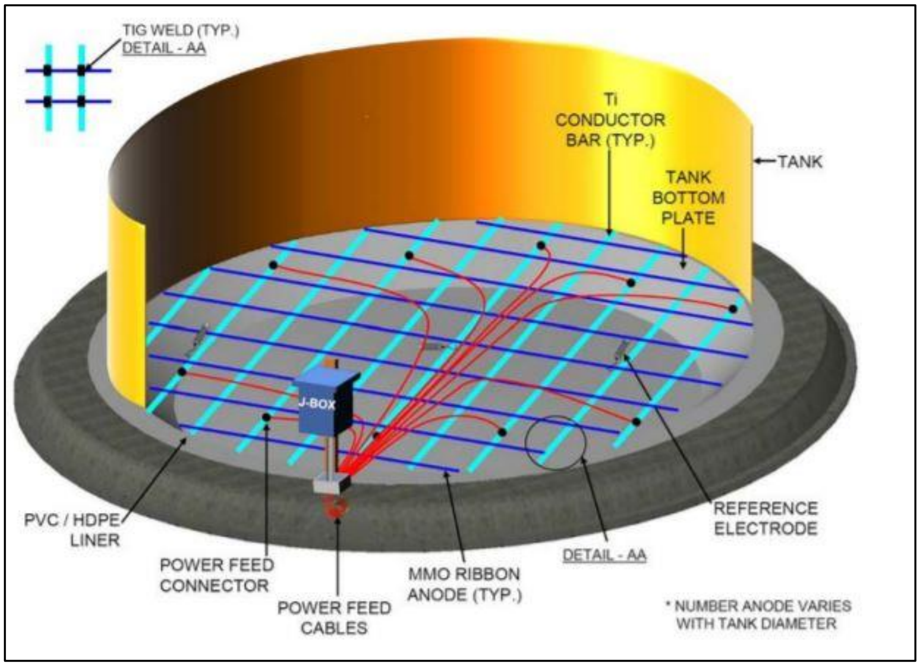

Figure 14 – Grid Type CP System

Most operators worldwide monitor their CP systems in accordance with recognized industry standards that have been developed by the National Association of Corrosion Engineers (NACE). In the case of aboveground storage tanks, the CP criteria are defined in NACE SP-0193 (or RP-0193).

Based on APSC's CP data, the NACE criteria that APSC uses for assessing tank cathodic protection are:

- An IR-free potential of -850 mV
- 100 mV of polarization

These criteria were established through laboratory and empirical testing. They define the conditions required to retard corrosion. If an operator meets one or both of these criteria, the structure is considered to be protected from corrosion.

There are some recognized limitations to these criteria for CP.

- NACE has stated that under normal circumstances steel cannot be polarized beyond -1150 mV.[1,2] This means that the IR-free or instant off data can generally not be more negative than -1150 mV (versus a copper/copper sulfate reference electrode). Data near this value and lower (more negative) should be looked at as suspect and further assessed for accuracy.
- The NACE standard requires that assessments for identifying 100 mV of polarization be determined through the measurement of the formation or the decay or polarization.[3]

[1] NACE CP-3 Cathodic Protection Technologist Manual, January 2010, Chapter 2, Paragraph 2.2.3.1.
[2] Barlo & Fessler, "Interpretation of True Pipe-to-Soil Potentials on Coated Pipelines with Holidays." CORROSION 1983.
[3] NACE SP0193-16, "Application of Cathodic Protection to Control External Corrosion of Carbon Steel On-Grade Tank Bottoms."

APSC provided PWSRCAC with Tank 7 and 8 CP monitoring data for the years 2016-2018. An excerpt of the Tank 8 data is provided below in Figure 15.

Alyeska Pipeline Service Company

Test Point Inspection Grid

Segment Code and Pipe	Inspection Date	Location (ft)	Calculated Shift (V)	Structure P/S (V)	Structure IRF (V)*	Effective Depol Date	Effective Depol P/S (V)
TANK 08 - NORTHEAST TUBE	6/24/2017 11:04:40 AM	90	0.332	-1.524	-0.514	7/13/2015	-0.182
TANK 08 - NORTHEAST TUBE	5/30/2018 09:41:50 AM	90	0.289	-1.411	-0.471	7/13/2015	-0.182
TANK 08 - NORTHEAST TUBE	6/27/2016 03:59:22 PM	100	0.42	-1.376	-0.57	7/13/2015	-0.15
TANK 08 - NORTHEAST TUBE	6/24/2017 11:06:00 AM	100	0.463	-1.294	-0.613	7/13/2015	-0.15
TANK 08 - NORTHEAST TUBE	5/30/2018 09:42:40 AM	100	0.417	-1.025	-0.567	7/13/2015	-0.15

Figure 15 – Excerpt of Tank 8 CP Data

Columns 1 and 3 ("Segment Code and Pipe" and "Location") of the data in Figure 15 indicate the location that the readings were taken. Column 2 ("Inspection Date") indicates the date that the On and IR-free (or instant off) data was collected. Column 4 ("Calculated Shift") indicates the calculated shift or degree of polarization on the structure (this is the number is to be compared against the 100 mV criteria for cathodic protection). Column 5 ("Structure P/S") of Figure 15 is the on potential. This can be used for troubleshooting but is not useful for determining the level of protection of a structure without accounting for voltage drop in the soil. Column 6 ("Structure IRF") provides the IR-free or instant off data (this is compared against the -850 mV criteria for protection). Column 7 ("Effective Depol Date") provides the date that the depolarized readings were collected. Finally, Column 8 ("Effective Depol P/S") in Figure 15 provides the depolarized readings. The "Effective Depol P/S" (or depolarized) readings are subtracted from the "Structure IRF" (or instant off) reading to calculate the "Calculated Shift" or polarization. "Calculated Shift" or polarization values greater than 0.1 V meet the criteria of 100 mV of polarization.

The 2016-2018 Tank 8 CP "calculated shift" data indicates that the structure had between 131 mV and 585 mV of polarization. This indicates that 100% of the floor met the 100 mV of CP polarization criteria and was well protected from soil-side corrosion. However, the tank has been actively corroding at an average rate of 11 mils per year (mpy). The discrepancy between the reported CP levels and the tank floor corrosion rates suggests that the CP testing data may not be valid.

3.4.1 Depolarized Potentials

From Figure 15 and the rest of the Tank 7 and 8 CP data provided, we can discern that the depolarized data was collected in 2015, but the on and instant off data was collected in 2016, 2017, or 2018.

The depolarized voltage of a structure changes over time due to soil chemistry, temperature, moisture content, and even the application of CP.[4] For this reason, the NACE standard requires that the formation or decay of polarization be measured in order to utilize the 100 mV criteria. Measurement of the formation or decay of polarization must be done during the same relative timeframe as collection of the IR-free or instant off data. The use of 1-, 2-, or 3-year-old depolarized data to determine the polarization of a structure does not meet the

[4] Dr. T. J. Barlo, "Cathodic Protection Parameters Measured on Corrosion Coupons and Pipes Buried in the Field." CORROSION 1988.

requirements of NACE SP-1093 (or RP-1093) and does not provide accurate measurement of the true level of polarization.

Likewise, APSC's monitoring procedure, MP-166-3.23 "Facilities Cathodic Protection Systems," Revision 13, requires that areas not meeting -850 mV criteria be assessed for 100 mV of polarization. MP-166-3.23, dictates that areas failing the -850 mV criteria must be depolarized and that the operator, "Periodically check the structure to soil potentials at these locations until they have stopped shifting (depolarizing) or have shifted at least 100 mV more positive than the INSTANT OFF potentials that were recorded…"[5] This aligns with the requirements of NACE SP-0193. However, APSC's actual practice of using outdated depolarized data conflicts with these procedures.

The use of "Native State" or baseline potentials is also not appropriate for measurement of polarization. Native state potentials are the voltage of freely corroding steel (without cathodic protection) measured against a stable reference electrode. Freely corroding steel sees significant potential shifts over the course of time. A study completed by APSC and ARCO Exploration found that the potential of a freely corroding steel coupon shifted over 130 mV between 14 days and 74 days of burial of the coupon.[6] When APSC and ARCO developed the first CP coupons, they initially intended to use the native state (or freely corroding) coupon, along with instant off data from the CP coupon, to ascertain whether 100 mV of polarization had been achieved. The research referenced above, determined that the potential of the freely corroding coupon deviated significantly from the depolarized potential and could not be used to ascertain the level of polarization afforded a structure. This supports the dynamic nature of native state and depolarized data and further supports the NACE SP-0193 requirement that the formation or decay of polarization be measured for areas that fail to meet the -850 criteria for cathodic protection.

[5] MP-166-3.23, "Facilities Cathodic Protection Systems," Revision 13. Paragraph 4.8 Depolarized Potential Measurements.

[6] Stears, Degerstedt, Moghissi, Lara & Bone, "Laboratory Study on the Use of Coupons to Monitor Cathodic Protection of an Underground Pipeline." CORROSION 1997.

A review of APSC's historical depolarized data for Tank 8 also proves that the depolarized potential of a structure is dynamic and that the decay of polarization should be measured shortly after collection of the instant off (or IR-free) data. Depolarized data was collected on Tank 8 for each year between 2001 and 2006. Figure 16 presents the 2001-2006 annual depolarized data.

Tank 8 Depolarized Readings 2001-2006 (mV)						
Location - Northeast Tube						
	6/3/2001	6/4/2002	5/29/2003	6/19/2004	6/15/2005	6/10/2006
10'	-358	-408	-314	-356	-334	-380
20'	-347	-379	-305	-265	-233	-283
30'	-401	-317	-295	-220	-165	-238
40'	-476	-535	-804	-471	-304	-300
50'	-670	-923	-861	-728	-678	-620
60'		-910	-839	-813	-679	-889
70'		-820	-731	-811	-755	-899
80'			-924	-817	-767	-899
90'			-943	-866	-842	-908
100'			-937	-860	-820	-887
110'			-853	-844	-806	-884
120'			-925	-866	-820	-850
Location Southwest Tube						
	6/3/2001	6/4/2002	5/29/2003	6/19/2004	6/15/2005	6/10/2006
10'	-313	-269	-289	-358	-197	-246
20'	-292	-268	-282	-287	-191	-217
30'	-327	-227	-279	-311	-193	-228
40'	-329	-222	-240	-259	-167	-189
50'	-318	-212	-226	-220	-142	-236
60'	-321	-209	-254	-248	-210	-614
70'	-323		-661	-453	-390	-925
80'	-431		-956	-832	-646	-914
90'			-951	-878	-812	-957
100'			-959	-893	-837	-939
110'			-918	-891	-823	-922
120'			-926	-893	-824	-934
130'			-933	-896	-696	-917

Figure 16 – Tank 8 Depolarized Data 2001-2006

A cursory look at the depolarized data confirms that it is dynamic in nature and varies significantly from year-to-year. In fact, an assessment of the data shows that the lowest average year-to-year variation in depolarized values was between 2002 and 2003, when the average measured change in the depolarized potentials was 65 mV. The highest average year-to-year change in depolarized potentials for this period was between 2005 and 2006, when the average change was 123 mV.

Figure 17 presents a graph of the 2001-2006 year-to-year average change in depolarized potentials for Tank 8. A line showing the 100 mV criteria was added to the graph for reference. This clearly illustrates that the annual changes in the depolarized potentials on the tank are similar in magnitude to the criteria that is being measured against. In fact, between 2005 and 2006, the average change in depolarization potentials was greater than the 100 mV criteria that is being measured against.

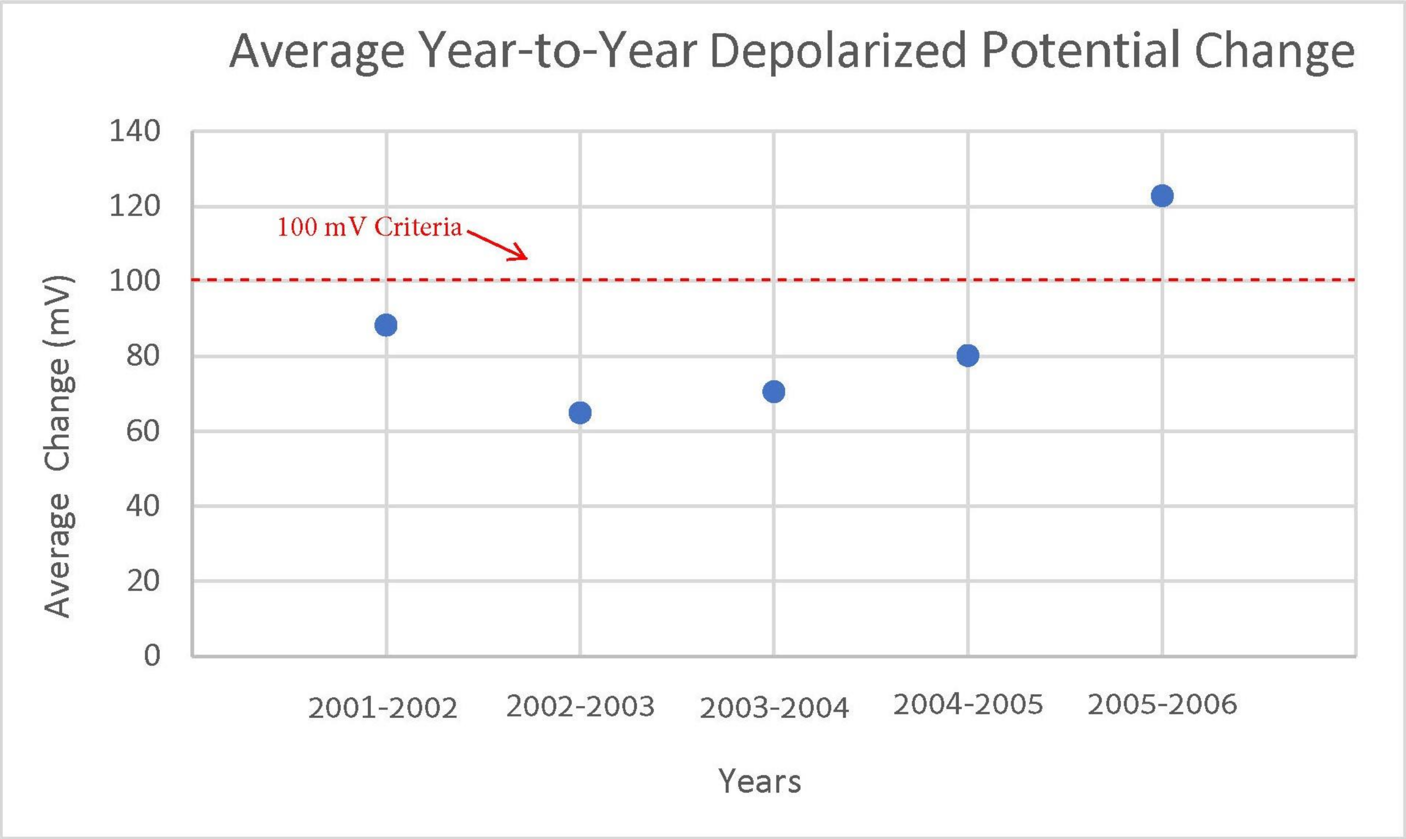

Figure 17 – 2001-2006 Average Change in Tank 8 Depolarized Potential Readings

The depolarized potential is used (with the instant off potential) to ascertain if the structure has 100 mV of polarization. These year-to-year changes in the depolarized readings on Tank 8, clearly illustrate why the standard requires that the operator measure the formation or decay or polarization each year. This data provides clear, empirical evidence that the practice of using depolarized data from past years will result in errors and invalid CP data. This supports the NACE SP0169 requirement that the formation or decay of polarization be measured in order to utilize the 100 mV criteria. The depolarized readings should be collected in the same relative timeframe (within weeks) of the collection of instant off or IR-free data.

Some may pose the argument that it is best not to depolarize the structures each year because it leaves the structure vulnerable to corrosion during the depolarized period. Depolarization of a large aboveground storage tank can take a week or more to occur. Although, the tank is not fully cathodically protected from corrosion while it is depolarizing, the tank surface is still partially polarized during the process and the time that it is depolarized is a very small percentage of the calendar year (2-4%). As in the case of Tank 8, incorrect measurement of the level of polarization afforded the structure, can result in an unprotected structure for 100% of the time. The risks of having a structure unprotected for a week or two during the collection of depolarized data is inconsequential compared to the risk of leaving a structure unprotected year-round due to improper data collection.

3.4.2 IR-free (Instant Off) Potentials

There are also issues with the IR-free (or instant off) potentials that have been reported. IR-free readings for Tank 8 were reported as negative as -1154 mV. IR-free readings for Tank 7 were reported as low as -2700 mV. These readings are beyond what NACE suggests are reasonable and should have been flagged as suspect by a qualified operator.

APSC appears to realize that there are inherent errors in their data. So, they have been including the following caveat with their cathodic protection data sheets:

- Note: readings more negative than -1.4V are due to being taken in close proximity to the MMO grid wires.

Regardless of the cause of the error, this statement is basically saying that the very negative readings include an inherent error and are invalid. If the proximity to the anode grid wires was the cause of the error as suggested by the APSC, then to collect accurate data, the operator would have to know precisely where the reference cell was in relation to each anode grid wire and they also would have to determine the minimum distance between the reference cell and anode grid wire that is necessary to collect accurate data. Figure 18 (below) is intended to depict the relative locations between the MMO anode grid wires, the slotted CP monitoring tube, and the floorplate. The CP reference cell is run beneath the tank through the slotted CP monitoring tube and data is collected at set distances from the tank shell. As can be seen from Figure 18, the reference cell will always be within 2-feet of the anode.

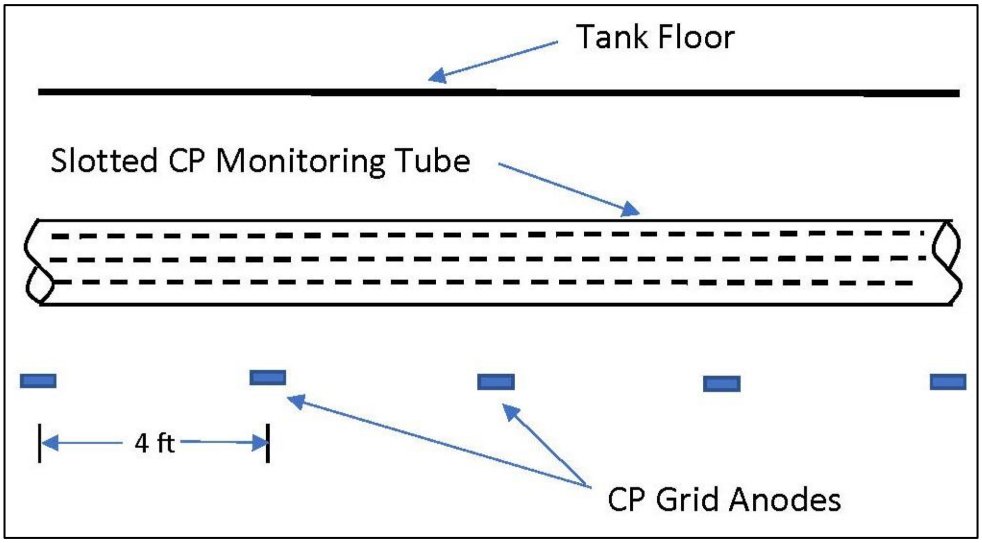

Figure 18 – Subfloor Anode/Monitoring Tube Locations

If the CP reading errors were caused by proximity to the anodes, then the magnitude of that error would gradually decrease as the distance from the anode increases. This decrease would continue until the reading was taken at the midpoint between two anode wires (as depicted in Figure 19), at which point the error would begin to increase again. If APSC's statement regarding proximity to the anode is accurate, this means that all CP readings collected beneath the tank are likely to be impacted by the same causal error, although the magnitude of that error may vary relative to the distance from the anode.

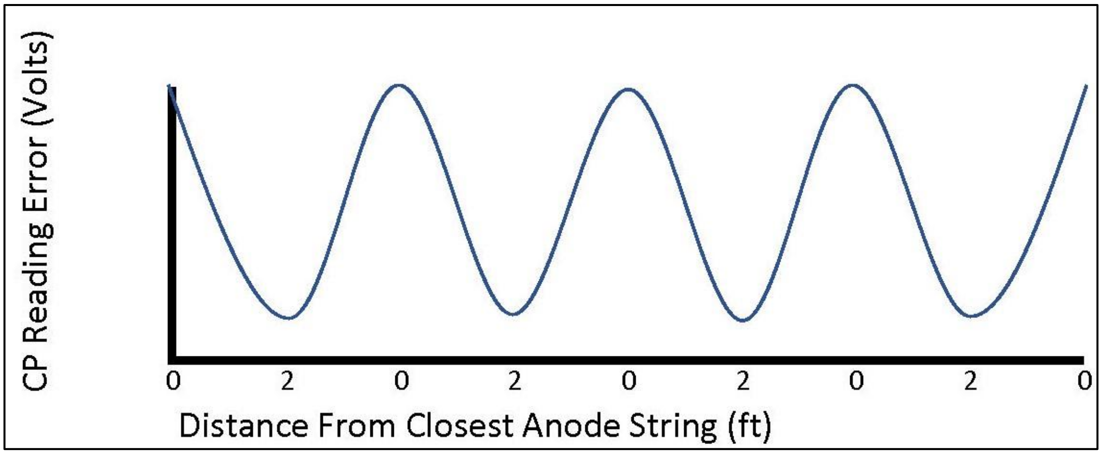

Figure 19 – CP Reading Error/Distance from Anode

In our professional opinion, the reasoning for the error that is cited may not be entirely correct. If all impacting CP systems are properly interrupted, then the field around the anode should collapse and the potential readings should not be impacted by the relative proximity to the anode.

APSC has stated that the very negative readings were taken too close to the anode, which implies that they are invalid. We concur that the very negative data is invalid. But as discussed above, the balance of the data, although less obvious, also carries an inherent error.

Figure 20 provides an excerpt for the data collected from Tank 7. To our knowledge Tank 7 was surveyed at the same time, by the same technicians, as Tank 8. Data for Tank 7 included “IRF” or instant off readings as low as -2.7 volts. This should have been recognized as erroneous by a qualified operator and should have prompted them to step back and assessed the measurement techniques being utilized. It appears that this was not the case and that the operator continued to collect and report obviously erroneous data.

FIGURE REDACTED AS PER APSC REQUEST

Figure 20 – Excerpt of Tank 7 CP Data

APSC has been struggling with the collection of accurate CP data on their tanks for over 17 years. In 2003, they commissioned Bob Gummow with Correng to study the VMT tank CP systems. Mr. Gummow came to some of the same conclusions that Taku has regarding the VMT tank CP system measurements.

Mr. Gummow's report to APSC stated that "potentials recorded that are more electro-negative than about -1350 mV_{CSE}, are kinetically improbable." He concluded that, "This suggests that there is an error in measuring the instant off data." He further stated that, "Any error in this measurement may have implications on the accuracy of the measurements at locations that are not so highly negative, and especially in determining the amount of polarization."[7] He is essentially stating that the extremely negative data is known to be erroneous and that all of the related data is likely to also have an inherent error, although it is less obvious in some of those data points.

As Mr. Gummow concluded in his 2003 study for APSC (which we agree with) that regardless of the source of the error, some level of that error is inherent in ALL data that has been collected in this fashion, not just the data points that are obviously erroneous.

To our knowledge, APSC is still collecting and reporting tank CP testing data in the same manner despite the conclusions that Mr. Gummow provided to them in 2003.

In summary, there are inherent systematic errors in the means and methods that APSC is using to collect CP data. This erroneous data collection is not limited to just the VMT crude tanks. Similar CP data has also been reported on the VMT piping and mainline TAPS.

This erroneous data leaves the operator, regulators, and general public with a false belief that the tanks and piping are protected from external corrosion, when in fact the structure may be exposed to elevated corrosion rates, as evident on Tank 8.

3.5 BOTTOMSIDE CATHODIC PROTECTION SYSTEM DESIGN

The tank CP system design does not appear to have maintained a consistent distance between the tank floor and the anode grid. The anode material was to be maintained at least 18 inches from the annual plate and at least 12 inches from the sump.[8] The inconsistent anode offset from the floor makes maintaining even current distribution across the floor much more difficult. This configuration would suggest that the CP current density afforded the outer perimeter floor plates would be roughly 50% lower than the CP current density afforded the floorplates near the sump.

The design also did not include the installation of CP ribbon beneath the annular plate. That suggests that some of the current intended to protect the perimeter floorplate will instead be picked up by the annular plate, further reducing the protection of the perimeter floorplates.

This may be in part why the majority of the floorplate repairs completed in 2007 and 2019 were located on the perimeter plates of Tank 8 (Figure 21).

[7] R. A. Gummow, "Review of Cathodic Protection Design for the Bottom External Surfaces of Crude Oil Storage Tanks at the Valdez Marine Terminal, Alaska." Prepared for Alyeska Pipeline Service Company, November 2003.
[8] Drawing D-54-E801 Sh.2.

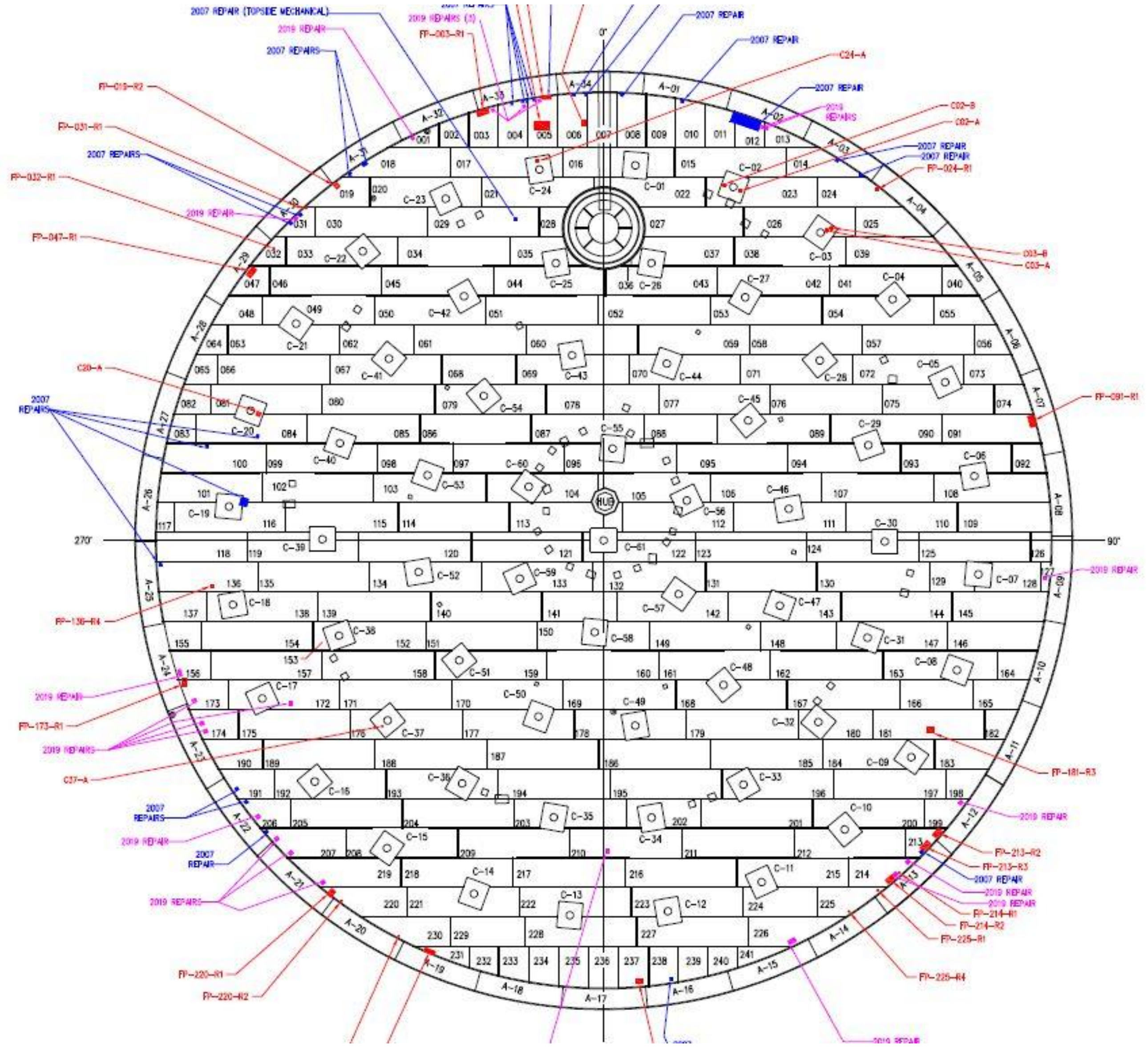

Figure 21- Tank 8 Repair Patch Locations

3.6 TANK SECONDARY CONTAINMENT LINER

The seals between the annular plate extensions and concrete ringwalls have not been maintained on the VMT crude tanks. This allows water to migrate between the floorplate and secondary containment liner on all tanks. However, water appears to accumulate beneath the floors on some tanks and not on others. This suggests that on some tanks, the sub-tank secondary containment liners may be leaking at a rate that is significant enough to drain the rainwater that is migrating beneath the tank floor.

In the past, APSC has conducted spot tests to determine the integrity of the secondary containment liners beneath the tank floors. However, these tests have been very limited in nature and do not constitute a statistically significant sampling of the liner area.

APSC should evaluate the secondary containment liners on a more comprehensive scale, to better define the condition of the secondary containment liners beneath the tanks.

4.0 CONCLUSIONS

APSC's equipment and processes for controlling and monitoring corrosion evolved significantly over the life of TAPS. In the 1990s inspection procedures were standardized and codified. Cathodic protection systems were added and enhanced. CP monitoring techniques were developed and refined to provide more accurate data and to meet the changing regulations. By 2000, TAPS had some of the most advanced corrosion control and monitoring systems of any pipeline company in the world. Many of these systems are used worldwide and were developed specifically on and for TAPS (such as CP coupons, ILIs, and telluric nulling CP surveys).

In some cases, APSC has maintained that high level of standard regarding corrosion monitoring and control. For example, the TAPS out-of-service, API 653 tank inspections, (with the exception of the initial 2019 Tank 8 inspection) are typically thorough, and competently executed. They usually meet or exceed industry standards and should leave the stakeholders with a high degree of confidence in the results.

However, in other cases, such as CP monitoring, APSC's practices have deteriorated dramatically. They have done a poor job of executing CP surveys in a manner that provide accurate results and are not producing results that ensure that the structures are protected.

Specific findings from this study are provided in detail below:

4.1 2019/2020 TANK 8 API 653 REPORT/TEMPORARY RETURN-TO-SERVICE

A. The initial 2019 API 653 inspection of Tank 8 was flawed. That inspection failed to identify much of the critical corrosion in the tank. This was a near-miss and could have ultimately resulted in a leak in the tank. Despite our requests, APSC failed to provide any significant information on the first inspection that could have enabled us to identify the causes of the failure and make recommendations to ensure that they are not repeated.

B. The second 2019-2020 API 653 Inspector of record for Tank 8 is in good standing as both a licensed Civil Engineer in the State of Alaska and as an API 653 Certified Tank Inspector. Likewise, the NDE inspectors taking part in the second inspection appear to be properly trained and certified through ASNT or the inspection company.

C. The corrosion rates used for the second Tank 8 API 653 assessment and return-to-service were conservative. It is highly unlikely that the tank will leak during the current service interval (2020-2023) due to bottom-side corrosion.

D. The 2020 API 653 report was silent regarding tank settlement evaluations that should have been completed during the 2019-2020 API 653 Inspections.

4.2 TANK SUBFLOOR WATER ACCUMULATION

A. APSC has not been maintaining the seal between the annular plate extension and the tank ringwall. This allows some of the rainwater that falls on the tank to migrate into the soils between the tank floor and secondary containment.

B. If the tank secondary containment liner is fully liquid-tight, the soils between the floorplate and secondary containment liner will be saturated within a relatively short period of time.

C. Water-saturated soils between the floorplate and secondary containment liner will impart buoyant forces on the tank sump and adjacent floor. This could cause the sump and surrounding floorplate to float when the tanks are empty.

D. Water-saturated soils in contact with the floorplate will increase the risk of corrosion and can establish differential cells across the floor that may further accelerate corrosion.

E. Drainage systems installed under some of the tanks are installed too high to fully alleviate the risk of sump displacement.

4.3 TANK BOTTOM-SIDE CATHODIC PROTECTION MONITORING

A. Cathodic protection monitoring data at the VMT is not being collected in accordance with industry standards (NACE RP-0193), regulatory requirements, or APSC's internal maintenance procedures (MP-166-3.23). Specifically:

  i. Many of APSC's instant off (I/O) readings are not accounting for all voltage drop (IR). Many of the reported I/O readings are too negative to be realistic.

  ii. APSC is not measuring the formation or decay of polarization when considering the 100 mV criteria for CP.

B. The errors in CP data collection that are obvious with the VMT tanks, appear to be systematic and are not limited to just the VMT tanks. Replacement of the Tank 8 CP system will not fix this issue. It will be necessary for APSC to correct their data collection and follow recognized industry standards, applicable codes, and their own maintenance procedures when monitoring CP to correct this problem.

C. The 2016-2018 CP data provided for Tanks 7 and 8 is not valid. The 2016-2018 data suggests that Tank 8 is fully cathodically protected from bottom-side corrosion (using the 100 mV of polarization criteria). The high corrosion rate on the tank floor shows that the CP system is not protecting the floor and indicates that the CP readings are erroneous.

D. 2001-2006 CP system data for Tank 8 shows that there is a significant year-to-year change in the depolarized potentials for the tank. This provides empirical proof that it is not valid to use outdated depolarized data to measure the level of polarization on the tank and re-affirms the practices required by MP-166-3.23 and NACE RP-0193.

4.4 TANK BOTTOMSIDE CP SYSTEM DESIGN

A. The CP system installed beneath the tank floor does not maintain a consistent distance from the floorplate to the anode grid. The anode installed near the tank sump is significantly closer to the floor. That will make it difficult to distribute CP current evenly across the floor and make it more difficult to protect the tank floor near the shell.

B. The existing CP system provides a lower current density to the plates at the tank perimeter than it does to the plates near the center of the tank. The system does not allow for the adjustment of current distribution to specific areas.

C. The existing CP monitoring tubes are not slotted beneath the annular plate. This prevents the operator from monitoring CP in that area.

4.5 TANK SECONDARY CONTAINMENT SYSTEMS

A. Water reportedly accumulates beneath the floors on some tanks and not on others. This suggests that the sub-tank secondary containment liners on some tanks may be leaking at a rate that is significant enough to drain the rainwater that is migrating beneath the tank floors.

5.0 RECOMMENDATIONS

5.1 2019/2020 TANK 8 API 653 REPORT/TEMPORARY RETURN-TO-SERVICE

A. APSC should share the original Tank 8 inspection results and the results of the ensuing investigation so that PWSRCAC can provide feedback and recommendations for avoiding similar failures in the future.

B. Conduct perimeter settlement surveys on Tank 8 in 2021 if none were completed during the 2020 API 653 Inspection.

C. Adhere to the current plan to remove Tank 8 from service and replace the floor and CP system in 2023.

5.2 TANK SUBFLOOR WATER ACCUMULATION

A. Use the existing drainage systems and CP monitoring tubes to remove as much accumulated water as possible from between the floorplate and secondary containment.

B. Maintain inventory in the crude tanks to at least 1 foot of depth at the perimeter until more detailed assessments on subfloor water accumulation can be completed on each tank. This will overcome potential buoyant forces on the sumps under the worst-case scenario.

C. Replace and maintain the seals between the tank annular plate extensions and the ringwalls to prevent future water migration into the tank subfloor areas.

5.3 TANK BOTTOM-SIDE CATHODIC PROTECTION

A. APSC's CP Operators should adhere to APSC's Monitoring Program, MP-166-3.23. Specifically, section 4.8 which requires that for areas not meeting the -850 mV criteria for CP, the CP systems be shut down and the potentials be checked periodically until they have stopped shifting (depolarizing). This would also put them in compliance with NACE RP-0193 (or SP-0193) which allows them to measure either the formation or the decay of polarization in order to ascertain the level of polarization.

B. APSC should collect depolarized data each year for areas not meeting the -850 mV criteria for CP. They should stop using old, depolarized data. The Tank 8 depolarized data provided in Section 3.4.1, shows that the depolarized potentials for a structure vary greatly from year-to-year. The use of depolarized data from prior years introduces a significant error into the measurement of polarization.

C. APSC should fully account for all IR error in their CP instant off (or IR-free) readings.

D. APSC should correct the system-wide erroneous CP collection field practices that are being utilized in order to properly assess the level of CP afforded their structures and to comply with State requirements (18 AAC 75) Federal requirements (49 CFR Part 195) and recognized industry standards (NACE SP0193).

E. APSC should consider collecting full CP waveforms to enable them to collect valid data and to identify errors more easily in the data collected. Much of the IR-free CP data provided by APSC obviously still has some IR in the readings. The use of waveforms could allow APSC to accurately measure or calculate the level of polarization, without fully accounting for the obvious IR errors.

F. All CP data should be collected by individuals that are sufficiently knowledgeable and have the appropriate training to recognize abnormal conditions (abnormal CP readings). The operator should be provided with the leeway that allows them to investigate errors and modify their approach to ensure that valid data is collected.

5.4 TANK BOTTOMSIDE CP SYSTEM DESIGN

A. The replacement cathodic protection system should include a groundbed that is a consistent distance from the floorplate to ensure more uniform distribution of CP current.

B. The replacement CP system should also have the ability to adjust the groundbed circuit resistances or driving voltage, in perimeter areas, so that the levels of CP current can be balanced across all areas of the tank floor. This can be done with the installation of a separate groundbed and rectifier in the perimeter areas.

C. CP monitoring tubes beneath the tanks should be slotted through the area beneath the annular plate so that levels of CP in those areas can be adequately monitored.

5.5 TANK SECONDARY CONTAINMENT SYSTEMS

A. Rather than rely on historical spot checks of the condition of the VMT tank secondary containment systems, APSC should conduct systematic, comprehensive testing of the integrity of each tank's secondary containment liner.

6.0 REFERENCES

The following documents were reviewed in the course of this study:

- APSC Drawing D-54-C2 Sheet 15 – TYP FDN Details 54-TK1 Thru-14 East Tank Farm.
- APSC Drawing D-54-C285 Sheet 20 – Valdez Tank Maintenance Program Crude Oil Storage Tank Drainpipe Installation.
- APSC Drawing D-54-E806 Sheet 4 – Valdez Tank Maintenance Program Monitoring Tube Section & Soil Side Anode.
- APSC Drawing D-54-E801 Sheet 2 – East Tank Farm TKS 3, 4, 6, 7 & 8 Cathodic Protection Tank Plan.
- APSC VMT Tank 8 Rectifier Bimonthly Readings 2016-2018
- 54-TK-8, API 653 Inspection and Return-to-Service Summary Report. Dated 5/6/2020.
- API-653 Supplemental Tank Inspection Report, Crude Oil Storage Tank, Tank 8 (54-TK-8), Dated 10/20/07.
- APSC TK 07 & 08 CP Data 2016-2018.
- APSCMP 166-3.20, Tank Monitoring.
- APSC MP-166-3.23, Revisions 9, 13, & 15, Facilities Cathodic Protection Systems.
- 11/2/20 APSC Response to PWSRCAC request for information regarding Tank 8
- 4/8/2020 APSC Letter to ADEC "Alyeska 54-TK-8 Return-to-Service and Temporary Regulatory Relief Related to COVID-19".
- 4/30/2020 ADEC Response to APSC "Valdez Marine terminal Oil Discharge Prevention and Contingency Plan, ADEC Plan # 18-CP-4057; Temporary Waiver of Article 1 Prevention Measure".
- R.A Gummow, "Review or Cathodic Protection Design for the Bottom External Surfaces of Crude Oil Storage Tanks at the Valdez Marine Terminal". November 2003.
- APSC Tank 8 Cathodic Protection Data 2001-2006.