# Accufacts Inc.

"Clear Knowledge in the Over Information Age"

# *Observations on OSFM Letters of Decision for State Waiver Requests on Line CA-324 and CA-325A/B Related to Possible Restart*

**Prepared For**

## The Center for Biological Diversity
## &
## The Environmental Defense Center

**February 21, 2025**

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# I. Summary.

Accufacts Inc. ("Accufacts") was asked to provide my expert opinion on the Letters of Decision on the State Waivers for the startup of Line CA-324, CA-325A, and CA-325B ("Pipelines") made public in mid-January 2025 by the Office of the State Fire Marshal ("OSFM").[1] This report builds on a previous Accufacts report issued on December 20, 2024."[2] By agreement, a Consent Decree gives the OSFM main pipeline safety approval authority of the Pipelines if the OSFM's actions are not in conflict with PHMSA pipeline safety regulations, and if PHMSA decides the proposed state waiver alternative measures "provide an equal or greater level of safety."[3] It is my understainding that PHMSA can choose to: 1) Not comment on this matter allowing the State Waiver to occur and startup to proceed, 2) Not approve the waiver preventing the startup, or 3) Impose additional requirements to assure an equal or greater level of safety to current minimum federal pipeline safety regulations occurs.

The current coating installations do not provide "limited effectiveness of the cathodic protection system," as mentioned by the Decision letters issued by the OSFM. This I believe is a poor choice of words that understates the fact that the CP system is ineffective on most of the Pipelines' mileage. The OSFM is thus being asked to grant a state waiver on federal pipeline safety minimum requirements intended to address external pipeline corrosion from an ineffective CP installation, while relying on hydrotesting and various forms of inline inspection, ILI or smart pigging, to avoid pipeline failure from the resulting external corrosion.

The waivers attempt to allow startup of the Pipelines relying mainly on ILI technology to identify corrosion threats before failure. In addition, the Application by the Pipeline's operator appears to be relying on a circumferential magnetic flux leakage (MFL-C tool) approach run in February 2022 to argue for the removal of federal regulation requiring the 180 day condition for scheduling remediation of "corrosion of or along a longitudinal seam weld."[4, 5] Our experience with MFL-C tools is that if certain parameters are not incorporated, such ILI tools can miss a lot of cracks. I see no mention of such important conditions in the referenced letter that would demonstrate that this ILI run is reliable. I do not see sufficient justification to waive 49CFR452(h)(4)(iii)(H) as such a waiver would not provide an equal or greater level of safety as no carbon steel pipeline, even new modern steel pipelines, are invincible to corrosion attack.

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[1] OSFM letter to Sable/PPC Offshore Corp, "Letter of Decision on the Sate Waiver Request for Limited Effectiveness of Cathodic Protection on Thermally Insulated Pipeline and Corrosion of or Along a Longitudinal Seam Weld (CA-324) ("Decision Letter 324") and Letter of Decision on the State Waiver Request for Limited Effectiveness of Cathodic Protection on Thermally Insulated Pipeline and Corrosion of or Along a Longitudinal Seam Weld (CA-325A/B) ("Decision Letter 325A/B")", dated 12/17/24.

[2] Accufacts, "Evaluation of Las Flores Pipeline System Startup Proposal," prepared for The Center for Biological Diversity & The Environmental Defense Center, December 20, 2024.

[3] PHMSA website: https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-and-state-waivers-overview.

[4] Pacific Pipeline Company (Aka now as Sable/PPC) letter to OSFM, "Subject Pacific Pipeline Company (OPID 40475) State Waiver Application for the Las Flores Pipeline CA-324 (OSFM #00115)," July 10, 2023, p. 5 related to MFL-C February 2020 ILI run.

[5] 49CFR452(h)(4)(iii)(H).

A simple plot of the type and approximate milepost location of external corrosion such as wall loss or cracking, including field as well as ILI indications along the Pipelines, will underscore how challenging the operation of the present Pipelines will be without effective CP. Such a plot will clearly demonstrate that the Pipelines are not "like new" as indicated by some recent Sable/PPC representatives. Further explanation is also warranted as to why the pipeline operator assumes there is no SCC or SSC risks associated with water on the Pipelines.

A proposal to replace the Pipelines with a new smaller diameter heated pipeline that would be uninsulated and built with modern unshielding coatings was aborted.[6] This proposal would have permitted the CP system to do its job addressing external corrosion, while complying with federal pipeline regulation.

## II. The current installation renders the CP system ineffective.

The construction of Line 324 in the late 1980s utilized coal tar urethane coating applied to the bare steel pipeline, covered by sprayed on insulation to assure the pipeline was operated at higher temperatures. The insulation was then wrapped with a non-conductive polyethylene tape coating.[7] While there may be some confusion as to the coating installation on what is now named 325A/B, information leads us to believe this coating installation is similar on these pipelines as that on Line 324. To anyone vaguely familiar with pipeline external corrosion protection and cathodic protection ("CP") intent, this approach is a fundamental failure of design/installation reflecting much inexperience in pipelines. The polyethylene tape shields and prevents CP current from getting to the external pipeline steel, and the insulation system works to shield while increasing the likelihood of water in close proximity to the pipe, especially in areas where the coal tar coating directly on the pipeline steel has separated, or disbonded, from the pipe.[8] <u>With such heavy shielding there is thus no way for any CP system current to ever reach the pipeline to reduce/prevent external corrosion.</u>

With the exception of a few feet of buried pipe that has undergone repairs, replacing the existing poor design and coating installations with a few feet of dual epoxy coatings, the shielded CP system is ineffective. The various threats of external corrosion on the Pipelines are exacerbated by the elevated temperature, the potential for water to accumulate along the Pipelines via the insulation, the application of non-conducting tape wrap around the insulation, and the use of older coal tar coating directly on the pipeline that exhibits separation (aka disbondment) from the pipe steel. Disbonded coating in the wrong environments is especially conducive to cracking threats, such as SCC or SSC as discussed in this report. I have seen no convincing arguments that water environments conducive to corrosion cracking are not around or under the coating on the Pipelines.

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[6] Plains Administrative Draft EIR, "Plains Replacement Pipeline Project," February 2022.

[7] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA"), "Failure Investigation Report Plains Pipeline LP, Line 901 Crude Oil Release, May 19, 2015, Santa Barbara County, California, May 2016, Appendix E: Corrosion Control and Pipeline Conditions, page 1 of 4.

[8] *Ibid.,* Page 3 of 21, and Mechanical and Metallurgical Testing, Photos Figure 1 through 20.

## III. Compliance with CP regulatory requirements is ineffective, making performance with this regulatory requirement meaningless.

The Pipelines thus have ineffective CP protection from external corrosion that is exacerbated by operation of the Pipelines at elevated temperatures, seriously increasing corrosion rate as discussed in my previous report.[9] Attempts to gauge the effectiveness of the CP system utilizing CP performance measures identified in PHMSA regulations are meaningless in such heavily shielded installations. Just operating the Pipeline with CP "on" to meet federal minimum regulatory requirements will not prevent external corrosion attacks that can take on various forms on the Pipelines. It should be noted that the OSFM has required "Where the operator discovers external corrosion in combination with coating deterioration, the operator must recoat with a two-part epoxy. Sable must recoat in accordance with their repair procedure." which does allow repair replacing with the existing installation approach, given its many shortcomings to prevent external corrosion.[10] This requirement places the responsibility on the pipeline operator to identify when or if any, field digs should occur to confirm coating degradation. The operator should be primarily focused on identifying environments around the pipeline that are precursors to various forms of external corrosion attack, given the many conditions related to the pipeline design/installation conducive to external corrosion attack.

It is on the limited repaired sections, measured in feet, that the CP should be effective as such short length repairs replace the poorly designed shielding original coating installations. For the vast majority of the Pipelines mileage, however, the CP remains ineffective. The requirements to measure CP performance stated in 49CFR§195.2 (NACE SP 0169 – 2007 edition, paragraph 6.2.2) are meaningless when heavy shielding, such as that which occurs on CA-324 and CA-325A/B, prevents CP current from reaching the pipeline.

## IV. This is more than simple corrosion under installation (CUI) issue.

Considerable past discussions have suggested that this is a corrosion under installation (or CUI") problem implying that this is the only controlling issue. While CUI is certainly a contributing factor, the corrosion threats go well beyond CUI. As previously discussed, heavy shielding, the tape coating around the insulation, the vintage/type of coating directly on the Pipelines prone to disbondment, the operating temperature, and the environment around the Pipelines, work in concert to create external corrosion in its various forms. The Consent Decree is an agreement based on the premise that higher risks of external corrosion can be mainly addressed by ILI tools. The multiple forms of external corrosion which can occur on the Pipelines require various different approaches, beyond ILI, as discussed further in this report.

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[9] Accufacts, "Evaluation of Las Flores Pipeline System Startup Proposal," prepared for The Center for Biological Diversity & The Environmental Defense Center, December 20, 2024, p. 13.

[10] OS OSFM letter to Sable/PPC Offshore Corp, "Decision Letter 324 and Decision Letter 325A/B")," dated 12/17/24, pp. 11 and 11 respectively.

## V. External corrosion on buried pipelines falls into four major categories.

External corrosion on buried steel pipelines falls into four general categories: 1) wall loss or thinning of the pipe wall, 2) cracking or crack-like, 3) pitting, and 4) corrosion within dents.

1. **Pipe wall loss corrosion is generally understood to occur over larger areas of the pipe.**

   Internal or external corrosion can cause pipe wall thinning. Such thinning differs from pit corrosion discussed below, in that pipe wall loss thinning tends to occur over a wider area of the pipe. Despite previous multiple ILI runs, external corrosion pipe wall loss, or thinning, was the condition that resulted in the May 19, 2015 pipeline rupture failure. External corrosion on the shielded pipe allowed general corrosion thinning of the pipeline until the pipe failed under pressure. It should be worth noting that wall loss in excess of 0.8 wall thickness (actually 0.91) which occurred in the May 19, 2015 rupture, places the operator at great risks. Ironically, pipe wall loss is generally one pipeline failure threat that advances in the ILI technology over recent decades was intended to address, either with ILI mag flux or ultrasonic approaches which are different technical methods.

2. **Cracking or crack-like corrosion is usually an environmental threat difficult to assess.**

   This is associated with various forms of pipeline cracking, such as selective seam corrosion or stress corrosion cracking. While engineers like to think they can calculate time to failure, such time to failure estimates for these forms of corrosions are hard to reliably predict. Given the probability that such cracking, especially if in clusters, can interact with other cracks, or weaknesses in the pipe body near/at welds, makes prediction to failure highly unreliable. Such pipe weaknesses can occur at weld heat affected zones, at girth welds, or at manufacturing related pipe seams, in unpredictable ways that can quickly negate time to failure calculation/estimates, even if cracking potential is identified.

   Sable/PPC has requested an exemption from 49CFR452(h)(4)(iii)(H) explaining this is usually a SSC threat related to earlier vintage manufacturing processes such as LF-ERW which tends to exhibit lower pipe toughness. There are other related risks to the manufacturing process of modern steels such as DSAW and HF-ERW concerning cracking potential from poor coating/ineffective CP approaches. Because of the nature of disbonded coating in proximity to water, coating can tent at weld seams creating potential for cracking corrosion attack, such as SSC. Even modern pipe steels are not invincible to such cracking corrosion potential, especially on pipelines operating at elevated temperatures. Unless the operator can show why such environments don't exist, their request to be exempted from 49CFR452(h)(4)(iii)(H) should be denied. These explanations should go well beyond a MAG-C pig run the pipeline operator has provided.

3. **Pitting corrosion is a special form of wall loss that is difficult to identify via ILI.**

   This is the loss of pipe steel in concentrated small areas, forming localized small holes or pits, usually at girth welds, that can weaken the pipeline and cause a release. Pit corrosion identification via ILI, even newer generations of ILI tools, can be very challenging. Pit corrosion threats are usually verified via field digs or pipeline releases. While this threat can be a bona fide threat on the Pipelines that are heavily shielded rendering CP ineffective, there has been no mention that this threat has been identified.

4. **Corrosion within dents is a special form of dent threat.**

   Corrosion or cracking within a dent, also known as "dents with stress concentrators" are hard to identify via ILI, and almost impossible to reliably predict time to failure. Such threats are usually identified by high-definition geometric ILI dent tools, the location around the pipeline, and field dig verification assessments. The ILI determination using high resolution caliper or geo pigs, have proven reliable at identifying dents and their location on a pipeline.

## VI. Types of ILI technology.

Given the possible types of external corrosion on the Pipelines, I now focus on a simple high-level discussion of corrosion ILI technical approaches.

1. **General wall loss corrosion.**

   After the advancement of geometric or deformation ILI technology, the next early phase of ILI use focused on general corrosion wall loss, or pipeline thinning along the axis or flow direction of the pipeline. In this field, technology split into two different approaches, magnetic flux leakage and ultrasonic. Magnetic flux leakage (or mag flux) approaches utilized software algorithms to characterize changes in magnetic flux to identify wall loss aligned in the axial, or direction of flow, usually the most insidious and common corrosion flaws for pipe. Mag flux ILIs fall into two general categories: low resolution (usually associated with earlier generation) and high resolution (usually more complex and more expensive). Mag flux technology shifted from low resolution to the more sophisticated high resolution approaches where corrosion is problematic. There are still pipelines that utilize low resolution mag flux because of cost, so care should be exercised in the application of this form of ILI on liquid pipelines. The waivers specifically require UT ILI the first two years of operation, but are moot, indicating magnetic flux ILI in the future could be allowed without clarification as to high res or low res ILI.

   Ultrasonic ILI approaches use beams of ultrasonic energy to identify both external and internal corrosion wall loss. While a simplification, ultrasonic approaches are analogous to radar, where reflected energy readings are utilized to measure changes in pipe wall thickness. Originally, ultrasonic approaches, focusing on wall loss evaluation, directed UT energy directly into the pipe in the radial direction for wall thickness and resulting wall loss corrosion sizing determinations.

**2. Cracking corrosion.**

Pipeline ruptures from cracking threats drove a need for ILI tool cracking development. Thus, a next generation of ultrasonic ILI approaches advanced by changing the angle of the UT beam from radial into the pipe to at an angle to help spot cracks that might be developing. This form of UT approach is identified as shear wave. As more pipeline failures from cracking were uncovered, additional advances known as phased array ultrasonic (PAUT) have recently developed, though such measurements are currently focused on field measurement of uncovered pipeline, as ILI in this area I would categorize as still under development.

I have investigated too many pipeline ruptures that occurred after an ILI run which indicates more regulatory work is needed in ILI regulations related to applications of ILI. No ILI vendor provides such tools claiming they will not work. It is the pipeline operator's responsibility to ensure ILI runs meet the restrictions placed by the tool vendor (such as speed) and to verify the tool vendor's claimed capability with a proper number of field verification digs.

## VII. What is the purpose of hydrotesting?

There are basically two types of hydrotesting mentioned in federal pipeline safety: 1) What I call a subpart E, or proof of MOP test, and 2) a crack hydrotest, what is referred to as a "spike hydrotest" that is performed at much higher test pressures as a %SMYS. Both forms of hydrotesting are proof test, good at the time of the test, and don't characterize time dependent pipeline threats such as corrosion.

The purpose of an MOP hydrotest is to proof the fitness for service of a pipeline at the time of the test, with a certain margin of pressure safety that usually deteriorates with time. Subpart E MOP tests are not crack integrity test. If a pipeline system has crack forming potential an MOP test is not appropriate.

Spike hydrotests are meant to avoid pressure reversals associated with crack threats on pipelines. Pressure reversals are where cracks remaining after MOP hydrotest tests can enlarge for various reasons to result in possible failure during operation, usually at lower pressures. It is my experience that spike hydrotests are meant to deal with cracking threats if such a threat exists. The performance metric for the suitability of a spike hydrotest is the range of %SMYS for the specific test segment. For pipeline elevation changes like that associated with 325A/B, a spike hydrotest requires the pipeline be segmented to keep test pressures within reasonable ranges that don't produce permanent yielding of the pipe. The information made public to date indicates that the previous hydrotests performed in 1986, because of elevation changes, required Line 325A to undergo hydrotesting in 9 segments and in Line 325B in 11 segments. Unfortunately, the hydrotest segments in the public record application are identified by station number and not by approximate milepost. Since there is usually no correlation between station number and milepost, I thus cannot evaluate whether the Decision Letter 325A/B pressure testing parameters are adequate for Line 325A.[11] It is worth noting that the Decision Letter 325A/B makes no mention of a subpart E

[11] Decision Letter 325A/B, "Pressure Testing," page 5.

hydrotest or spike hydrotest on Line 325B. The proposed segments for hydrotests on 325A need to be identified by approximate milepost to permit evaluation as to whether the waiver requirements are appropriate. The reasons for hydrotesting exclusion on Line 325B need to be properly justified and made public by the OSFM.

## VIII. The illusion that corrosion growth rate can be accurately predicted needs to be explained.

One of the critical parameters that I have observed in too many pipeline rupture investigations is that ILI can be utilized to accurately predict corrosion growth rates ("CGR") to help set a critical ILI run timing, for example. The Pipelines essentially have no effective CP, operate as a higher temperature system, contain disbonded coating, incorporate heavy shielding which prevents CP from reaching the Pipelines and operate with insulation that moves water on/near the outside of the pipe. Such a combination of factors can provide a wide variation in types of external corrosion as well as corrosion rate estimates. CGR estimates can be especially problematic if CGR approaches miss possible corrosion interaction threats that can considerably shorten time to failure estimates. I advise that CGR be utilized with extreme caution given this possible variation, especially for corrosion threats that can interact, such as SCC, whose time to failure can be highly unpredictable. Corrosion growth rate estimates can vary considerably given the various form of external corrosion, especially related to cracking in combination with its location near sensitive pipe locations such as seam or girth welds.

## IX. Major state waiver deficiencies:

Key observation on the state waivers for the Pipelines:

1. **A key corrosion performance tracking process step in the state waivers for the Pipelines is missing.**

   While not specially required in minimum pipeline safety regulations or the waivers, a prudent pipeline operator on a pipeline system highly susceptible to corrosion will plot or graph corrosion indications by type and severity, by approximate milepost. This is especially important on the Pipelines given their history of extensive corrosion caused by the lack of CP effectiveness, poor coating types causing disbondment or shielding, increased temperature, insulation that tends to wick water, and poor performance of ILI. Such graphing aids a pipeline operator in understanding possible corrosion "hot spot" segments whose threats on a pipeline increase because of environmental factors that merit additional assessment, and maybe even pipeline segment replacement from a corrosion point of view.

   Care also needs to be taken that all corrosion sites are prudently evaluated for possible interactive threats, such as general wall loss in combination with cracking, or near pipe welds, such as that which can occur with cluster corrosion. I see no mention in the Letters of Decision and waivers requiring such important corrosion tracking on the Pipelines.

## 2. A major state waiver deficiency for Line 324.

Given the pipeline properties stated for Line 324 (a single grade X65, 0.344 in wall thickness, 24-inch diameter, HF-ERW), I can calculate the various % SMYS for the spike (minimum and maximum test pressures, and MOP hydrotests) based on an estimated approximate elevation profile by milepost as Line 324 can be hydrotested as one segment given its limited elevation profile.

A critical condition in the OSFM Decision letter 324 is:

> "12. Prior to placing the pipeline in operation, Sable must conduct a spike hydrostatic pressure test of the state waiver pipeline segments at a minimum pressure that is at least 1.5 times the MOP or 100% SMYS, for a minimum of 15 minutes after the spike hydrotest is stabilized. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-324:
>
> a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
> b. All anomalies that have a predicted failure pressure less than or equal to 1.6 times MOP."[12]

For the 24-inch diameter pipe, wall thickness and grade stated in the Decision Letter 324, 100% SMYS calculates to 1863 psig. 1.5 times the stated MOP of 1003 psig calculates to 1504 psig, at the highest elevation point. Thus, the spike test at the highest elevation point as required above is likely to be the lower maximum test pressure of 1504 psig which calculates to about 81% SMYS**, a value I believe is too low for corrosion cracking screening and evaluation**. The OSFM needs to explain why the proposed spike hydrotest of Line 324 is so low.

The bottom line is that Sable/PPCs should demonstrate whether there are environmental conditions around Line 324 that are conducive to cracking either SCC or SSC, and these conditions should go well beyond a Mag-C tool run (such as sufficient field digs to verify the ILI tool's claimed capability). I see no such important conditions in Sable/PPCs application that instill confidence that Line 324 does not have environments favoring external cracking. While it is true that certain pipe manufactured before 1970 is more prone to SSC, or SSWC, for various reasons, there is no modern pipe, even HF-ERW located in Line 324 or DSAW located in 325 A/B, that is invincible to such corrosion cracking threats, especially if the coating directly applied to the pipe has "tented" on the weld seam, allowing water to enter between the coating and the pipe to create a corrosion cell. There is no carbon steel pipeline, even new modern manufactured steel pipelines, invincible to such corrosion attack.

[12] Decision Letter 324, "Pressure Testing," pages 4 – 5.

3. **Major state waiver deficiencies for Line 325A/B.**

Decision Letter 325 states that Line 325A and 325B is composed of 30-inch diameter of two pipe grades (X65 with a thickness of mainly 0.344 inch and X70 with a wall thickness mainly of 0.281 inches composed of DSAW, with one small segment of 0.03 miles containing HF-ERW). I used the term “mainly” as Sable’s/PPC’s application indicates these two lines are also largely composed of these grades with a small percentage of varying thicknesses.[13] For these two pipe grades, and thicknesses, 100 % SMYS calculates to 1490 psig for X65 and 1311 psig for X70. Since the location of the various pipe grades by approximate mileposts within CA-325A/B are not indicated, and given the dramatic elevation profiles for 325A/B the proposed hydrotest segments, if any, by milepost and elevation segments need to be made public. Without such information, I cannot calculate the % SMYS range for hydrotests given the OSFM conditions. Hydrotest segments are identified by station number which don’t necessarily sync with milepost or MP.[14] **These important test segment parameters, by approximate MP, and elevation need to be made public to assure prudent hydrotesting is being required to address the possible general corrosion and cracking risks on Line 325A/B**.

It is worth noting that the OSFM does not require a MOP and spike hydrotest of 325B which has very significant elevation changes. This would suggest that Line 325B is not being evaluated by hydrotesting. The reason(s) for this decision needs to be made public.

## X. Conclusions.

Hydrotest segments proposed for the Pipelines need to be made transparent and include approximate MP, given the major role that elevation change plays on this system. Critical parameters related to location by milepost of the varying grades and thicknesses of pipe on 325 A/B and their associated hydrotest segments need to be identified by approximate MP as well, to verify if the OSFM parameters are sufficient for the specific types of corrosion threat. The reason as to why a spike hydrotest on 324 and 325 A are limited needs to be explained, as well as to why 325B hydrotesting has not been included in either a subpart E or spike hydrotest,

The incompleteness of the waivers lead me to conclude that I cannot determine the waivers provide sufficient information to assure an equal or greater level of safety for the Pipelines had the operator had an unshielded coating design that complied with federal minimum pipeline CP protection intended to avoid pipeline failure from external corrosion.

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[13] Sable/PPC letter to OSFM, “Subject Pacific Pipeline Company (OPID 40475) State Waiver Application for the Las Flores Pipeline CA-324 (OSFM #00115). Pipeline System Background Data Attachment B of State Application Table B-3 Line Pipe Specifications,” July 2023, p. 4.

[14] *Ibid*., “Table B-6 Historic Hydrotest Summary,” p. 6.