BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

MEGHAN FLYNN	:	
ROSEMARY FULLER	:	
MICHAEL WALSH	:	
NANCY HARKINS	:	
GERALD MCMULLEN	:	DOCKET NOS. C-2018-3006116
CAROLINE HUGHES and	:	P-2018-3006117
MELISSA HAINES,	:	
Complainants	:	
v.	:	
	:	
SUNOCO PIPELINE L.P.,	:	
Respondent	:	

SURREBUTTAL TESTIMONY OF MEHROOZ ZAMANZADEH, Ph.D. ON BEHALF OF FLYNN COMPLAINANTS

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Attorney for Complainants

Q. Before proceeding with surrebuttal testimony, I would like you to state your certification related to corrosion

A. I'm a NACE certified Corrosion Specialist.

Q Is either Mr. Field of Mr. Garrity a Corrosion Specialist?

A. No. Mr. Garrity earned a BS in Electrical Engineering. He is a certified NACE CP Specialist. Mr. Field earned a BS in Mechanical Engineering. He is a certified NACE CP Specialist.

Q. What is the difference between a CP Specialist and a Corrosion Specialist?

A. A Corrosion Specialist has earned NACE Institute's highest level of certification. The Corrosion Specialist certification is geared towards very experienced corrosion control personnel, with broad and extensive expertise, in both the theory and practice of multiple areas of corrosion and corrosion control, and capable of performing work at a very advanced level. A CP Specialist has not taken the higher level examination that a Corrosion Specialist has.

I believe there are around seven (7) NACE certified Corrosion Specialists in Pennsylvania, 151 NACE certified Corrosion Specialists in the USA and 286 NACE certified Corrosion Specialists in the world.

Q. What are the steps to corrosion specialist certification?

A. The NACE requires you first to have qualified as one of several lower level specialists, including CP Specialist. You then appear to take the certification exam. I took it, passed it and was then certified as a Corrosion Specialist.

Q. Dr. Zee, have you had an opportunity to review the Rebuttal Testimony of John G. Field III and the Rebuttal Testimony of Kevin C. Garrity that have been submitted in this proceeding?

A. Yes, I have.

Q. Have you had an opportunity to review the exhibits that accompanied the testimony of Field and Garrity?

A. Yes, I have.

Q. Can you identify the Field exhibits?

A. Sure. The exhibits noted in Mr. Field's testimony were identified as JF-1 through JF-5.

Q. What were JF-1 and JF-2?

The first two were stated by Mr. Field to consist of the Energy Transfer Integrity Management Plan applicable to Mariner East pipelines in May 2018 (ETIM Plan) and the Sunoco IM Plan applicable prior to that date. I am assuming that Mr. Field examined the same documents that my team and I examined at Matergenics in 2019.

Q. How about JF-3 through JF-5?

A. JF-3 is identified by Mr. Field as a document reflecting 32 standard operating procedures and one engineering standard. JF-4 is spreadsheet purporting to show various MFL, deformation and UT in-line inspection tool runs for each pipeline. ~~JF-5 is a metallurgical leak analysis prepared by DNV GL USA, Inc. (DNV Report).~~

Q. Until you received Mr. Field's testimony, had you ever seen exhibits JF-3 through JF-5?

A. The answer is definitely not. JF-3 appears to be a compilation that Mr. Field prepared for his June 15, 2020 testimony. It was not available to me at the time I submitted my direct testimony on January 15, 2020, six months earlier. JF-4 is a table of inspection dates. Again, it appears to be a compilation by Mr. Field for his rebuttal testimony. Some of the information underlying the document may have been produced previously. ~~As for JF-5, the DNV report, the first time I saw it was in connection with Field's rebuttal testimony. I should note that Sunoco's PHMSA report in connection with the April 1, 2017 leak incident may have contained some information provided by DNV but I am uncertain of that.~~

Q. Can you identify the Garrity exhibits?

A. Mr. Garrity's testimony includes two tables he prepared that are identified as Figure 1 and Figure 2. It also includes his curriculum vitae, marked as Exhibit KG-1. He refers to the five Field exhibits as well as information available on the PHMSA website. I'm not aware of any other Garrity exhibits.

Q. For the testimony that you are about to give, have you reached your own conclusions to a reasonable degree of professional and scientific certainty?

A. Yes, I have. All of my comments as well as conclusions in this surrebuttal testimony are given to a reasonable degree of professional and scientific certainty.

Q. Let's start then with Mr. Field's testimony. Regarding Exhibit JF-3, have you determined which of those operating procedures and one engineering standard went into effect after the Morgantown incident?

A. Yes, all of them. ~~Every single one went into effect one year or longer after the ME1 April 1, 2017 leak in Morgantown.~~ I have prepared a table that identifies all of these by procedure number, title, effective date, and code (49 CFR 195) reference for each. I have attached that table as Exhibit Zee-1.

Q. Mr. Field states in his rebuttal testimony that "SPLP has and follows robust integrity and corrosion control assessment and management practices…" Was that statement true at the time of the April 1, 2017 Morgan leak incident?

A. No, it was not. First, as to the integrity assessment and corrosion control assessment and management practices in the immediate vicinity of the leak incident, the practices newly *adopted* and shown in my table are good practices. Obviously, they were adopted in response to the absence of such practices leading up to the incident. Second, the fact that they were adopted does not by itself mean they were *implemented*. ~~If there are data that reflect implementation of these practices in the Morgantown vicinity, those data have not been shared with Matergenics.~~ Mr. Field does not identify any records that support the sweeping generality that on April 1, 2017 or later on "SPLP has and follows robust integrity and corrosion control assessment and management practices." This is true ~~both respect to Morgantown in particular and~~ the entire Mariner pipeline system as well. This also is obvious from the fact that many of Sunoco's sub-part practices are specifically identified in my initial direct testimony and not one of my comments identifying those practices is criticized by Mr. Field.

Q. Dr. Zee, have you reviewed Field Exhibit JF-4?

A. Yes, I have reviewed Exhibit JF-4. The two tables presented in the exhibit provide historical details concerning ILI segments, inspection dates, inspection tools, and inspection vendors for both the 8-inch ME1 pipeline and the 12-inch GRE pipeline. ~~The inspection dates for the 8-inch ME1 pipeline range between 1990 and October 15, 2019.~~ The inspection dates for the 12-inch GRE pipeline range between 1996 and August 31, 2018. This exhibit does nothing to change my opinion, as it only provides very generalized information concerning the occurrence of the ILI inspections, and does not provide a record of the details or the results of any of the inspections. To be useful, a detailed inspection file containing the details and the results the individual inspections would be required.

Q. Regarding the DNV Report, Exhibit JF-5. do you agree that the report makes clear that the pipe segment that is the subject of the report ("the pipe segment") was removed from the pipeline by Sunoco, and not by DNV?

A. Yes. On page 1 of the DNV report the following statement was made, showing that DNV did not remove the pipe section, but that the pipe section was shipped to DNV. Figures 1 and 2 on page 25 of the DNV report are documentary photographs of the arrival of the pipe segment at DNV. The report specifically says, "The pipe section containing portions of the upstream (U/S) and downstream (D/S) joints and a chill ring was sent to DNV for analysis. The objectives of the analysis were to determine the likely metallurgical cause(s) of the leak and to identify any contributing factors."

Q. Do you agree that the pipe segment removed by Sunoco and delivered to DNV was approximately 8 feet long?

A. Yes. The photograph provided in Figure 4 on page 27 of the DNV report documents the length of the pipe segment at approximately 8 feet.

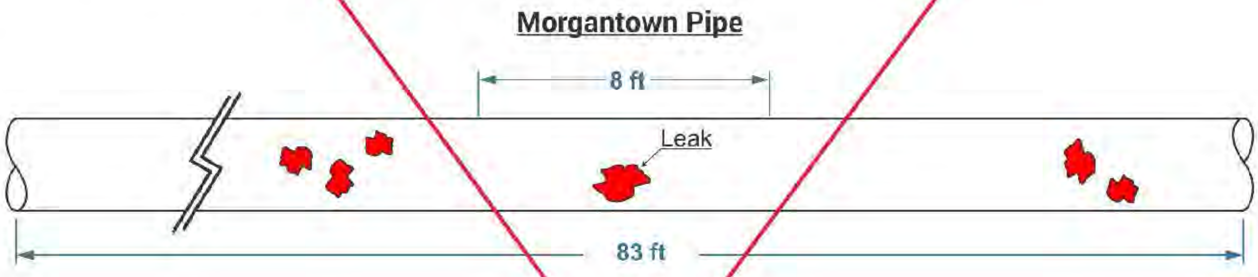
Q. Did you find any reference in the DNV Report to the existence or condition of ME1 pipe adjacent to the pipe segment?

A. No, I did not. Nothing in the report suggests that DNV made an on-site investigation of the pipe. Nothing in the report comments on the existence or condition of the ME1 pipe adjacent to the pipe section they received for failure analysis.

Q. Is that concerning to you?

A. Yes, it is. Look, the area of the leak itself can be thought of as a small patch. Think of cancer surgery for a moment. The doctor removes more than just the tumor; there is a margin around the tumor that also is removed. So, it was reasonable to remove a length of pipe bigger than the leak site. But now go back to a cancer patient whose tumors may have metastasized. When you're doing the surgery, do you look around to see if there might be more tumors? Of course you do. The two existing ancient Mariner pipelines were not coated and they did not have any cathodic protection for many decades. Mr. Field is a corrosion engineer. He knows that there was a reasonable suspicion after April 1st at least that there were other spots of corrosion adjacent to the leak. Indeed, in his testimony he states, "Many corrosion features on these pipelines were a result of corrosion occurring during the first 30-40 years of service life, before cathodic protection was applied to the entire pipeline." But Field was not at the site at the time the 8 foot section was taken out and neither were the authors of the DNV Report. I understand that ME1 is over 300 miles long and the 12-inch line may be 24 miles long.

Here is a simple graphic that makes this obvious point:



Given these concerns, it is puzzling that the DNV Report and Mr. Field simply fail to see an elephant in the room when Sunoco installs a new 83 foot, hydrostatically tested pipe segment into the 8 foot opening left by the removal of pipe to send to the DNV lab. This is not mentioned by DNV. It is not mentioned by Mr. Field either. Obviously, 83 feet (more or less) of ME1 pipe was removed by Sunoco after the leak incident. Where did the other 75 feet go? What was its condition? Why is Sunoco going out of the way not to address the absence and the condition of the missing pipe? Importantly, no records have been supplied to Matergenics that address this matter.

Q. Do you know definitively what caused the leak at Morgantown?

A. No. First, not based on the DNV report or on any records previously supplied. In fact, the DNV Report notes that the leak portion of the 8 foot pipe segment had been contaminated before it arrived at the DNV laboratory for examination. Again, people are familiar from television with the work that crime scene technicians do at the scene of crimes. Contamination of a crime scene often makes it impossible to obtain a definitive forensic result. Now look at the DNV Report. It states in part that [redacted] This is an example of tampering with or contaminating the evidence, so that a proper examination and analysis of the leak location could not be undertaken. In data processing they have a saying, "Garbage in, garbage out." So, too, DNV was doomed from the start. It does seem possible and even probable that MIC was responsible. In order to get a clearer picture, however, an investigator would have needed an uncontaminated scene and also would have had to perform other tests that DNV apparently did not perform.

Q. You said "first." Is there a "second?"

A. [redacted] I cannot think of a better way to make it impossible to determine the cause of a leak on a corroded pipe. DNV must have been informed by a Sunoco agent or employee that this had occurred. Was the decision to do this made by someone in the field or by someone higher up? Once again, I have been given no records that explain how this was allowed to happen. In the context of a decision to remove 75 additional feet of possibly corroded pipe, this is something that needs to be addressed.

Q. Do you agree that the DNV Report concludes that MIC "may have contributed to the observed corrosion?"

A. In the Executive Summary of page iii, and in the Conclusions on page 12, both in the DNV report, the following statement was made. "Given the lack of corrosive species and neutral pH of the soil, microbiologically influenced corrosion (MIC) may have contributed to the observed corrosion."

I, personally, suspect that MIC is more likely than not as the culprit, but we can never know because of the site contamination and failure by DNV to conduct appropriate testing. In my previous testimony, based solely on the PHMSA report and on my own experience, I was more definitive. I did not know at the time about Sunoco having contaminated the site; if I had I would have been less definitive.

Q. What is "active" corrosion and why is this an issue?

A. Active corrosion in this case is defined as the degradation of metal by soil environment through electrochemical process. Active corrosion can be identified by direct and indirect assessments and thickness loss measurements in advance prior to perforation on a pipeline. Perforation of an underground pipeline by corrosion process is certainly an indication of active corrosion and inadequate corrosion control.

Q. **Field states in his rebuttal testimony, "Many corrosion features on these pipelines were a result of corrosion occurring during the first 30-40 years of service life, before cathodic protection was applied to the entire pipeline. The vast majority of the corrosion observed in these tables is not active." Do you have a comment on what Mr. Field is saying here?**

A. Mr. Field's statement is based on a number of assumptions and data that he has not shared with us. First, for ~~both the 8-inch line and~~ the 12-inch line, he offers no data, no facts based upon shared records concerning whether or not documented corrosion that occurred 40 – 50 years ago is active or not. Sunoco's records say nothing about whether documented corrosion is active, so his comment is nothing more than surmise. Second, and more troubling, he is making the unwarranted assumption that any corrosion that existed from inception of cathodic protection is now under control and, therefore, not active. It cannot be assumed that corrosion ceased entirely on the pipeline since the application of cathodic protection, and that all observed pipeline corrosion ~~occurred during the first 30-40 years of service life.~~ ~~Along more than 324 miles of Mariner pipelines there may be sections where cathodic protection is quite good and there may be~~ sections ~~where it is quite bad.~~ Without reference to real data, once again, there simply is no way to know. This assumption is not technically sound without proper and extensive field evaluation of effectiveness by measurements, such as pipe-to-soil potentials.

Q. Same quote from Mr. Field. Do you have any idea to which corrosion features he is referring?

A. No, I don't. Again, he makes reference to no records, no data, that support his statement.

Q. **Mr. Field states in his rebuttal testimony, "SPLP has taken steps to either repair or replace the pipe where corrosion limits its integrity. Steps have also been taken to stop the corrosion from growing or to reduce its growth by increasing the cathodic protection current…" Do you have any idea at what locations Field believes that corrosion limited the integrity of either of the two old Mariner pipelines?**

A. Mr. Field does not say. From our own review of the records, in particular the integrity management summary documents that we discuss on page 25 of my report, there is documentation [redacted] The twenty-two ILI inspection anomaly report documents discussed on page 26 of the Zee report [redacted]

Q. **Did corrosion limit the integrity of the 8 foot Morgantown pipe segment?**

A. Mr. Field does not comment on that. In Table 3 on page 14 of the DNV report, however, [redacted] at the location of the external corrosion of the 8 foot Morgantown pipe. This is considered significant as it would require repair if not removed from the main pipeline. Based on prior document review, [redacted]. Therefore, we can state that the integrity of the pipe was compromised at this location.

Q. Your table covers the changes made in IM that began in April, 2018, a year after the Morgantown incident. Does that table actually identify locations on ~~ME1 and~~ ME2 where Sunoco has documented it has increased the cathodic protection current?

A. No, not at all. You could state that Sunoco purports to have adopted new standards. That, by itself, does not mean they have implemented the standards or, if they have, whether cathodic protection has effectively been increased.

Q. What is the reason that Sunoco increased the cathodic protection current in the Morgantown area?

A. Sunoco has not shared any records with me so I cannot say for sure. It seems likely it was because of the failures at Morgantown.

Q. Do you agree that, prior to the Morgantown incident Sunoco's records indicated cathodic protection readings of -628 millivolts ("mV") in 2016 and -739 mV in 2015 at station 2459+00, which is approximately 1,030 feet from the leak,

A. This information came from the BI&E complaint. Sunoco has not shared any records concerning this with me so I cannot say for sure. These readings are not sufficiently negative to ensure adequate cathodic protection. At least -850 millivolts are required to ensure adequate cathodic protection if MIC is not present. As indications of possible MIC are mentioned in the DNV report, -950 millivolts or lower would be more appropriate.

I would like to highlight that during the review of IM within a limited time, our team has noticed the following statement in the document No. SPLP00032079: **"The goal is to have pipe-to-soil ON potential of greater than -0.85V".** Also, in the document No. SPLP00032019, under sub-section 10.6 of *indirect inspections* and sub-section 10.6 of *classification of survey indications* the following was mentioned:

Table 10-1: Severity Classification

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted] This was mentioned in my earlier testimony.

Q. Have you found any place in the Field testimony that comments on the presence or absence of records of side drain measurements in Sunoco's records?

A. It's not there. This is significant in a conversation about cathodic protection and corrosion. This may be because he agrees with my report but he did not say so.

Q. Mr. Field's rebuttal testimony notes the absence of documentation of stress corrosion cracking on the ~~ME1 and~~ ME2 pipelines. Can you identify the factors that contribute to stress corrosion and state whether or not any of those factors have been noted in ~~ME1 and~~ ME2 records?

A. Let me quote from my own direct testimony, from page 9:

"Stress corrosion cracking (SCC) is a form of corrosion cracking that is associated with near-neutral pH or high pH. For near neutral pH stress corrosion cracking, the electrolyte contains a dilute solution of carbon dioxide and bicarbonate ions with a pH between 6 and 7. This type of corrosion cracking is associated with limited branch transgranular cracking and the crack walls contain corrosion products. High pH SCC is caused by a solution of carbonate ions with pH between 9 and 10.5 exhibiting intergranular cracking with limited branching. Stress corrosion cracking can initiate under disbonded coatings that may shield cathodic protection."

Reviewing the tables of soil analysis data, Tables 11 and 12, on page 19 of the DNV report, [redacted]

The suggestion that stress corrosion cracking has not occurred yet means that it will never occur is unfounded. As part of cathodic protection one wants to make sure the conditions that lead to SCC do not take place. Mr. Field has not challenged my basic finding that this soil chemistry might be considered conducive to development of SCC.

Q. Mr. Field's rebuttal testimony discusses stray current and interference bonds. Do you have any comment on that discussion?

A. Yes, once again he makes sweeping generalizations without reference to records, data, facts. For instance, he says that "SPLP corrosion technicians are very active in the Eastern Pennsylvania and Western Pennsylvania Corrosion Control Committees." With all due respect, attending meetings is not the same as meeting engineering standards and implementing proper practices. Fields fails to identify anything in my direct testimony on this topic that is erroneous and he fails to identify any records that document the actual presence or absence of stray current or interference bonds on the ME1 and ME2 pipelines.

Q. Do you have any comment on what Mr. Field says about Kevin Garrity's testimony?

A. I reserve my comment on that to my testimony regarding Mr. Garrity. I will say, however, that for the most part Mr. Field's testimony is untethered from any discernible data.

Q. Do you have anything further to add relative to Mr. Field's conclusions?

A. Yes. First, Mr. Field's testimony does not state it is given to a reasonable degree of professional or scientific certainty. Second, there is no portion of the testimony identified as "Conclusions." Counsel asks him on page 4 to discuss issues that I raised in my earlier direct testimony. Perhaps those are his conclusions. There are 7 points he mentions, and I will now address those briefly:

(1) *Claim*: Zee identifies inspection techniques that ought to be followed. Part 195, however does not require those techniques. *Response*: Good engineering practices may call for more than meeting regulatory requirements.

(2) *Claim:* Zee fails to provide significant context regarding corrosion being active or not. *Response:* I have already addressed this in my surrebuttal testimony.

~~(3) *Claim:* Regarding MIC, Sunoco has changed its practices since Morgantown: *Response:* I have already addressed this in my surrebuttal testimony.~~

(4) *Claim:* Regarding stress cracking, it's never been a problem on the Mariner East pipes. *Response:* I have already addressed this in my surrebuttal testimony.

(5) *Claim:* Regarding stray current and interference bonds, Sunoco technicians attend meetings. *Response:* I have already addressed this in my surrebuttal testimony.

(6) *Claim:* Dr. Zee can find publicly available data on PHMSA's website to replace the poor copy of a previously produced document. *Response:* Since we cannot read the data in question we don't know what to look for on the PHMSA site.

(7) *Claim:* Dr. Zee says Sunoco does not do leak surveys. We are not required to do so. *Response:* Once again, good practice should trump minimum regulatory standards.

Q. Dr. Zee, having read Mr. Field's rebuttal testimony, what conclusions you have reached?

A. Nothing in Mr. Field's rebuttal testimony has caused me to change my mind. Except as noted above, the information and conclusions set out in my initial direct testimony stand.

Q. Now let's review Garrity's testimony. Mr. Garrity in his rebuttal testimony states that "Dr. Zee presumes that the presence of corrosion is a regulatory violation." Is Mr. Garrity correct?

A. The presence of accelerated corrosion and perforation is a regulatory violation. An inadequate or improper corrosion control program is a regulatory violation

Q. Garrity refers to the DNV Report as a "Root Cause Failure Analysis Report", What is a Root Cause Failure Analysis Report?

A. In general terms, a root cause failure analysis is a method of problem solving used for identifying the root causes of failures or problems. Root cause failure analysis generally serves as input to a remediation process whereby corrective actions are taken to prevent the failure or problem from occurring. The DNV report does not proceed to the final step to provide recommendations for remediation. They did not perform soil testing which is significant in corrosion failure analysis and determination of primary cause. The DNV report may more properly be called a metallurgical failure analysis report but not a root cause failure analysis report.

Q. Mr. Garrity refers to a review of "216 Dig Reports." He says that a review of the reports "did not reveal findings of MIC." Can you explain why these reports did not and would not reveal findings of MIC?

A. Dig reports consist of forms completed by Sunoco field technicians. I've provided a sample report, and it's been marked as Surrebuttal Exhibit Zee-2. These reports were inspection and repair reports. They were not prepared to evaluate or classify the corrosion mechanism. A finding of MIC would require familiarity with MIC testing. It was not performed on site due to lack of knowledge. Non-certified corrosion technicians are not trained to evaluate MIC. Also, as you can easily see, the reports do not call for a root cause failure analysis and so there is none. Hence, you would not expect findings of the presence or absence of MIC in the 216 Dig Reports. The absence of such findings, therefore, does not mean that there was no MIC and the suggestion by Mr. Garrity to the contrary is entirely unfounded.

~~**Q. How can reports that do not contain a root cause failure analysis be compared to the DNV Report that does have a root cause failure analysis?**~~

~~A. It's a case of apples and oranges. The comparison is simply not valid. Apparently, Mr. Garrity does not understand the difference between primary cause and root cause determination.~~

Q. Mr. Garrity suggests that you have ignored the significance of ILI. Is it Garrity's position that ILI does not monitor internal corrosion?

A. I have not ignored the significance of ILI. It is my contention that other state-of-the-art technologies exist to complement ILI, and they should be employed as well. It is a mistake to say that ILI together with CP is the "best technology." They are important tools, when used properly. The report on the 2016 failed ILI suggests that ILI is not always successful. Furthermore Mr. Garrity does not recognize ILI cannot detect initiation of corrosion. ILI cannot detect the initiation of corrosion and obviously perforation was not detected.

~~**Q. With all of Garrity's comment on the importance of root cause failure analyses, have you found any at all in your records review?**~~

~~A. Except for the DNV Report that was just produced to us, we have found none. And the DNV report is incomplete and does not address the source for accelerated corrosion and perforation.~~

Q. Sunoco has insisted that it was not required to meet the -850 mv standard for cathodic protection. You've reviewed the company's IM plans. Do the IM plans call for the -850 mv standard or the alternative criteria standard?

A. Sunoco's IM plans explicitly call for the -850 mv standard. The company has not even followed its own manual. I believe that the suggestion that they actually followed the alternative standard is not supported by their own records. If there are records that demonstrate they did, let Sunoco produce them. It is noteworthy that after the incident they realized the problem and established -950 mv as the criterion.

Q. Mr. Garrity concludes that the Sunoco and Energy Transfers' IM plans are adequate. Have you found anything in his testimony that explicitly critiques your analysis of the deficiencies in those plans?

A. No, I have not. ~~Furthermore, if Sunoco had plans that were adequate AND was following those plans, how do they explain what happened at Morgantown and why they devised new standards and procedures a year later?~~

Q. Garrity notes that the data presented in pages 11-12 of Dr. Zee's testimony "does not identify whether the observed corrosion was active or inactive." What is the significance of corrosion being active or inactive?

A. I have addressed this in my testimony in response to Mr. Field's testimony. Accelerated corrosion and perforation is considered an active corrosion. This is a very basic, fundamental concept in corrosion science.

Q. Have you found in Sunoco's records documentation that actually shows what CP criteria have been used on the ~~8-inch and~~ 12-inch pipelines?

A. No, I have not, ~~other than in the DNV Report, which was denied to us until recently.~~

~~**Q. Is it your contention that the information gleaned from the Morgantown investigation is sufficient to draw the conclusion that there is a system-wide failure of integrity management?**~~

~~A. Not at all. What we are saying, however, is that data provided by BI&E and by DNV and by Sunoco itself suggest that there may be a system-wide failure and that steps need to be taken to investigate further.~~

Q. What additional data would DNV have needed in order to determine more definitively whether or not MIC was the cause of the corrosion in the Morgantown incident?

A. Soil analysis, onsite spot analysis, collection of corrosion products, FTIR analysis of deposits. Direct microscopic examination of the leak pit was made and described on page 10 of the DNV report, with cross-section metallography, as being characteristic of MIC.

Q. From your examination of Sunoco's records and exhibits, are you aware of whether or not at station 2459+00 Sunoco performed side drain measurements on ME1prior to April 1, 2017?

A. It is possible that Sunoco shared that information with BI&E as well as DNV but my team did not find that information in the records supplied by counsel.

Q. If current is flowing away from the pipeline rather than towards the pipeline, is that a sign of corrosion?

A. Some conditions can establish anodes and cathodes on pipeline to allow the corrosion cells to exist. At the anodic area, current leaves the pipe to enter the surrounding earth, steel pipe will be corroded at this area as the current flow through earth from anodic area to cathodic area. There is a direct current flowing from anodic areas into the soil and onto the cathodic area, and back through the pipe itself to complete the circuit.

Q. Did Sunoco perform CIPS on ME1 prior to April 1, 2017?

A. It is possible that Sunoco shared that information with BI&E as well as DNV but my team did not find that information in the records supplied by counsel.

Q. Did the result of the 2017 ILI inspection on ME1 indicate any metal loss?

A. Yes. The twenty-two ILI inspection anomaly report documents discussed on page 26 of the Zee report document [redacted] This indicates presence of active corrosion which would result in perforation at a later time.

Q. What if any significance was there to a finding of metal loss?

A. Further corrosion risk assessment and repair may be required, depending on the depth of metal loss.

Q. What conclusions did you draw as to the cause of metal loss identified in the 2017 inspection?

A. From the report itself, none. Corrosion is one possible cause. The depth of metal loss observed in the ILI report means that one cannot rule out active corrosion as a possible cause. CP records should have been reviewed and soil investigation should have been performed.

Q. I will suggest to you that BI&E asserted in its complaint against Sunoco that the CIPS performed on ME1 prior to April 1, 2017 did not align with footages and test station points. If that were true, how you could Sunoco be sure that its assessment of ME1 cathodic protection was accurate and reliable?

A. In that situation Sunoco could not be sure.

Q. Do you have any reason to believe that the 12-inch pipeline is in any better condition or any worse condition than the 8-inch ME1 pipeline?

A. Based on the data summarized from the 216 Inspection and Repair - Maintenance Record reports in the two tables on page 11 of the Zee report, I would conjecture that the 12-inch pipeline is probably in worse condition than the 8-inch pipeline. But this is speculation and we must rely on facts. You could really only tell if there were a proper investigation, as I have recommended.

Q. Mr. Garrity says on page 9 of his testimony that "the age of a pipeline is not a key criterion for determining the safety of an operating pipeline." Is it your claim that age in fact is a "key criterion?"

A. For aging structures and pipelines, past is not indication of future. I would not use the phrase "key criterion." The factors that I believe are important in determining the safety of a pipeline are laid out in detail in my direct testimony. In general, aging underground pipelines are at risk of corrosion failure due to coating degradation, external corrosion and stress corrosion cracking. Corrosion failures in aging pipelines are either sudden catastrophic ruptures or gradual leaks due to localized corrosion and cracking. Many factors associated with these corrosion areas are coating failure, degradation, disbondment, blistering, delamination, mechanical pressure and stress concentration, galvanic action, corrosive ions, the presence of moisture, corrosive soils, stray current interference, AC interference, inadequate cathodic protection and shielding. These areas have a much higher statistical probability of catastrophic failure and rupture.

Most of the time initiation of stress corrosion cracking (SCC) and pitting corrosion are detected by coincidence in excavation and digs and is not targeted or predicted by analysis of corrosion performance parameters. Internal or ILI tools have limited capability for detecting or identifying stress corrosion cracking and pitting corrosion initiation.

It may be noted that aging, by itself, may not result in corrosion of a steel pipeline. In theory, it is possible that there will be constant/consistent soil conditions, coating conditions, absence of potential damage mechanisms/threats throughout the service life. But in reality, this just does not happen. Coating degradation and disbondment take place.

A pipeline will be exposed to various potential damage mechanisms/threats throughout its service life. If these damage mechanisms/threats are not identified, controlled and/or mitigated in time, it could result in pipeline failure. Typically, aging presents corrosion problems as well as corrosion induced cracking.

Cast iron, wrought iron and bare steel pose the highest risk compared to coated carbon steel. As the pipeline ages, coating on the pipeline could damage/disbond/delaminate and result in corrosion with age at the exposed areas in the aggressive soil conditions.

In our opinion, integrity assessment must be in place for aging pipelines. It is necessary that there be (a) External corrosion direct assessment (ECDA); (b) Internal corrosion direct assessment (ICDA); and (c) stress corrosion cracking direct assessment (SCCDA).

Q. Mr. Garrity in his rebuttal testimony does not address the finding by DNV [redacted] Do you have a view as to whether this failure to comment is significant?

A. Yes, I do. There is a Greek myth about a man named Procrustes. When travelers came to spend the night at his house, they slept in a bed that was used either to stretch or cut off the traveler's limbs. That way the travelers could be made to fit the bed. So it is sometimes with expert testimony. If you change enough facts, or ignore enough facts, you can reach any conclusion you like. The DNV Report was flawed by contamination; that is a fact that cannot be ignored. No firm scientific conclusions regarding the leak on April 1, 2017 are possible. At most, one may conclude that it is more likely than not that MIC was involved but that was never demonstrated.

Q. Mr. Garrity suggests that you have overstated the likelihood of the presence of MIC at the Morgantown leak site. Do you agree with that viewpoint?

A. Not at all. I have explained already in response to Mr. Field's comment that my previous view was based on limited data: Sunoco's PHMSA summary. I now have had a chance to look carefully at the DNV lab analysis and my view is even stronger. The suggestion that MIC is only a possibility is not borne out by Tables 9 and 10 or the additional data gleaned from Figures 26 and 27. MIC is more likely than not a cause of the corrosion in question.

Q. Why is it important to know whether or not MIC was involved at Morgantown?

A. The conclusion as to whether or not there was MIC is important because the presence of MIC suggests that cathodic protection is insufficient. If CP is not sufficient, then ultimately corrosion will take place, metal will be lost and leaks can develop.

Q. Can you put the DNV report in better context?

A. Sure. To start with, DNV's analysis was constrained by the actions of Sunoco. Before DNV even saw the 8 foot segment, Sunoco had (a) disposed of 75 additional feet of adjacent pipe without adequate condition assessment and documentation that may have had similar conditions; (b) [redacted]

Q. With all those concerns, can you testify whether or not there were any meaningful results in the DNV analysis?

A. Yes, there were. We can start with tables 9 and 10. The results of bacteria culture tests on swab samples as well as optical microscopy examination are reflected in DNV Tables 9 and 10. Those tables can be seen here:

[redacted]

	[redacted]		[redacted]		[redacted]		[redacted]	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 9 refers to bacteria culture testing. Bacteria culture testing is designed to determine the quantity of a given bacterium in a fixed-size sample. The objective is to count how many there are in that sample.

It is often the case that there are too many bacteria in a sample to count. The principle of serial dilution is that if the sample is substantially diluted in a solution, it will make it easier to count the number of bacterial cells.

For example, if you dilute the sample in solution by 1000 times and you are able to count 100 cells, then you can readily project the actual number of cells in the original sample. In this case, it is 1000 times 100 cells for a total of 100,000 cells. Dilution is often done enough times by a factor of 10 until there are no cells that can be counted in the last sample.

When you do serial dilution of samples taken from four distinct locations, you can quantitatively compare the concentration of bacteria among four separate sites. Thus, if Sample A tests positive in only one vial (the original vial containing bacteria), but Sample B tests positive in three vials, that implies that even with two 10 to 1 dilutions (a factor of 100x), Sample B still tests positive – therefore it appears to have a higher number or concentration of bacteria by a factor of 100x as compared to Sample A. Note: A result showing zero indicates that no bacteria of a given type were detected at a given location, as even the original undiluted vials did not show the presence of the bacteria.

[redacted]

The connection between number of bacteria and MIC is this. In general, we may say that a low to moderate number of all bacteria types were detected at the sampling location on the pipe, and this suggests that MIC may exist on the pipe.

The major issue here is that corrosion products and bacteria colonies on pitted areas/soil were not analyzed, photographed or considered. This is a serious shortcoming in corrosion risk assessment and quantification of risks for a pipeline that exhibits perforation due to corrosion.

Q. What does Table 10 tell us?

A. Table 10 reflects a separate approach to bacteria identification. [redacted]

The overall picture is further completed by cross-section microscopy of corrosion pits at the leak site. [redacted]

Q. With these three separate sets of tests, can you draw any conclusions about the presence or absence of MIC at the leak site?

A. Yes, I can. In total, the DNV laboratory undertook three distinct approaches to explore the possibility of MIC at the leak site. Taken together, they constitute scientific proof of the existence of MIC at the leak site. The level of certainty is higher than simply "suggestive" or a "possibility." It is "more likely than not."

Further, the fact that Sunoco later on saw fit to adopt standards that required an increased CP potential clearly indicates that Sunoco believed either that (a) the Morgantown leak was the result of insufficient cathodic protection, or (b) the company saw MIC in other locations of the pipe, or (c) both (a) and (b).

Q. Do you have any concerns about Mr. Garrity's failure to discuss these three separate tests in his testimony?

A. Yes, of course. This goes back to the Greek story of Procrustes. Mr. Garrity has drawn conclusions about a report that he either never read or that he decided to ignore. Data from three separate sets of tests is completely ignored. The most polite way to describe what he has done is simply to say it is unscientific.

Q. How about the missing pipe?

A. Well, there is also missing testimony, is there not? Mr. Garrity has chosen to ignore DNV data and he also pointedly ignores the same elephant in the room ignored by Mr. Field: the missing 75 feet of ME1 pipe. For all he knows; that pipe was thoroughly corroded and his client, Sunoco, disposed of it so that there would be no evidence of corrosion. Mr. Garrity writes that Sunoco and Energy Transfer have robust corrosion control and integrity management programs and SOPS. He does not, however, critique any of our direct testimony detailing many examples where this is shown not to be true. Moreover, along with Mr. Field, he deliberately fails to distinguish Sunoco's practices leading up to April 1, 2017 from its practices after April 1, 2018. In fact, he talks about Sunoco's "program" but he does not pay any attention to actual data that would support or not support the claim that the program is actually operational.

Q. On page 15 of his testimony, Mr. Garrity says that prior to May 2018, SPLP used the net protective current criterion on bare or ineffectively coated segments of the pipeline. Have you found any place in the IM plans that says that?

A. If it's there, I haven't seen it. So far as I know, this is something that Sunoco came up with in response to the BI&E complaint proceeding.

Q. On page 15 of his testimony, Mr. Garrity says that SPLP uses a combination of CP criteria as listed in the applicable NACE standard RP (SP) 0169 Control of External Corrosion on Underground or Submerged Metallic Piping Systems as provided for under 49 C.F.R. § 195.571. Do you have any comments on his statement?

A. According to him, SPLP uses a combination of CP criteria: a) ON Pipe-to-Soil potential of -0.85 volt, or more negative, with respect to a copper-copper sulfate (CSE) reference electrode and b) net protective current criterion (special condition as per NACE SP0169-2007).

Garrity does not discuss the findings highlighted in Exhibit 13 – Summary of Sunoco CIS document review, where it is evident that at most of the locations ON potentials are more positive than -0.85 Volt. So, ON Pipe-to-Soil potential of -0.85 volt, or more negative, with respect to a copper-copper sulfate (CSE) reference electrode criterion is not satisfied.

Regarding net protective current criterion, he is hiding the fact that though net protective criterion is sufficient for bare or ineffectively coated pipelines, in some situations, such as the presence of sulfides, **bacteria**, elevated temperatures, acid environments, and dissimilar metals, this criterion may not be sufficient.

Earlier, we were not sure of the CP criteria used so we did not comment on the righteousness of the CIS data. However, from Garrity's testimony it is clear that SPLP is claiming that it used net protective current criterion. From the CIS data, however, it is evident that net protective current measurement techniques set out in NACE TM0497 were not actually followed. Mr. Garrity should have highlighted this but he did not.

Net protective current criterion is used as a last resort criterion. Moreover, it is used in situations where another criterion cannot be easily or economically met. Application of net protective current measurement technique as per NACE TM0497-2002 is as follows: a) Depolarize structure, b) Perform pipe-to-electrolyte survey or two-reference-electrode surface survey to locate anodic areas. c) Energize CP system and d) Use side drain method at anodic locations.

Exhibit 11 shows that CIS data was collected by a) CP Data Manager in 2009, b) TITAN TSC in 2013, 2016 and 2017 and c) Corrpro. Only Corrpro has followed NACE TM0497-2002 requirements. However, they did not collect side drain potential readings. CP Data Manager did not measure side drain potential readings at all anodic areas. CIS data collected by CP Data Manager in 2009 reveals that almost the entire length of the pipeline surveyed is more electropositive than -850mV. At some locations the side drain potentials were around -261mV.

Here is a good example that each contractor that performed CIS has followed different procedures which clearly indicates that SPLP has no standard procedure and no clarity on the CP criteria to be followed. If IM is technically sound as claimed by Garrity, all contractors would have followed same procedure for structure-to-soil potential survey.

I also would like to mention that some pipeline companies use the side drain method for the application of net protective current criterion. In response to BI&E, SPLP claimed that they used this method. No reference is found in 49 CFR 195 regarding the acceptability of this method. NACE SP0207 addresses the measurement survey technique. It is worth stating that the results of side drain method could be misleading if there are any outside sources of influence such as other pipelines or other gradient sources such as stray currents. The results might also be questionable in areas with **high resistivity surface soil**, for deeply buried pipelines, or where **local corrosion cell exists**.

We haven't seen any soil data to comment whether soil has high or low resistivity.

Moreover, we must bear in mind that side drain measurement technique should be used with caution. Under certain conditions such as presence of bacteria (SRB), a relatively strong localized anodic cell could exist on the bottom side of the pipe with the top of the pipe serving as a cathode and negative side-drain readings could be measured while severe corrosion is actually occurring on the bottom of the pipe at this location.

I would like to bring to your notice that net protective current criterion is specified in older versions (RP0169-2002, SP0169-2007) but is no longer specifically listed in SP0169-2013.

Q. Dr. Zee, in connection with Sunoco's experts testifying that the company has solid integrity management plans as well as robust practices, did you have occasion to review a PHMSA Notice of Probable Violation notice to Sunoco dated February 4, 2019, that relates to cathodic protection practices in Honeybrook, Pennsylvania?

A. Yes, this was brought to my attention recently.

Q. Do you recognize surrebuttal Ex. Zee-3 as that PHMSA notice?

A. Yes, I do.

Q. Do you know where Honeybrook, Pennsylvania is located?

A. Well, now I do. It's in Chester County.

Q. So this notice is not about Morgantown, but rather a separate area on the ME1 pipeline?

A. Yes, that's right.

Q Before we go into the details, can you just summarize what the notice says?

A. Sure. PHMSA say that their representatives performed inspections on the ME1 pipeline system at Honeybrook in Chester County during the period from March 19, 2018 to March 23, 2018. Sunoco is alleged by PHMSA to have failed to provide cathodic protection that complies with NACE criteria. PHMSA also says that Sunoco's records were not sufficient to demonstrate adequacy of its corrosion control measures. Finally, PHMSA talks about limitations on the utility of the ILI techniques.

Q. From the information in the PHMSA notice, can you tell if the inspectors confined their investigation to just one location on the ME1 pipeline?

A. They did not. PHMSA identified nine (9) distinct locations at which they took readings.

Q. Would you quote from the third page of the notice in § 6.3 relative to ILI?

A. Yes. "The in-line inspection technique, however, may not be capable of detecting all types of external corrosion damage, has limitations in its accuracy, and may report as anomalies items that are not external corrosion."

Q. Do you have a belief as to whether this supports your view or Mr. Garrity's view?

A. I believe ILI is an important tool but it is just one of several. I think Mr. Garrity has over-emphasized its importance and under-emphasized other important tools.

Q. As you read the PHMSA notice, what are they saying about the cathodic protection measurements that they took?

A. Basically, they are saying that the -850 mv criterion has not been met and the alternative earth current technique criteria have not been demonstrated either.

~~**Q. How many years' records were reviewed by PHMSA in connection with this violation notice?**~~

~~A. 2015 – 2017. I'd like to point out that the inspectors noted that "no IR free readings were provided when utilizing the -850 mV SP 0169 criterion…Additionally, Sunoco did not provide a valid explanation for how IR drop was being considered when evaluating the adequacy of the readings that were taken."~~

~~**Q. What are IR free readings and why is their absence a problem?**~~

~~A. IR free readings are those reads that consider IR drop in soil. Their absence introduces extensive errors in the data and corrosion risk assessment.~~

~~**Q. Do you have any idea if Sunoco responded to this notice or satisfied PHMSA that the notice was in error?**~~

~~A. I do not know how this situation resolved. I can tell you, however, a number of things. First, PHMSA's explanation of NACE standards is correct. Second, the inspectors report that they did not find "records in sufficient details to demonstrate the adequacy of corrosion control measures." This is consistent with our findings during the review of tens of thousands of pages of Sunoco's records provided during this case. This supports our contention that the conclusions of Mr. Field and Mr. Garrity, that Sunoco's integrity management practices are robust and compliant with federal regulations, is unsupported by real-world data and has no foundation in Sunoco's own records.~~

Q. It has been suggested that you are calling for a massive program of laboratory sample testing. Dr. Zee, are you calling for a massive program of laboratory sample testing?

A. No, not at all. The soil testing is less than $500, Spot testing is less than $200. Miscellaneous tests at about $500; all less than $2,000. This provides fantastic results with other data if unacceptable risks at this site (pretty much like indications of cancer in blood). Massive cost? Apparently, they have never approached these types of problems with testing to have high confidence...or trying to scare the audience.

Q. Do you have anything further to add relative to Mr. Garrity's conclusions?

A. Yes. Mr. Garrity sets out 7 conclusions:

(1) *Claim*: There's no evidence the IM plans are inadequate. *Response:* That conclusion is not supported by the facts as set out in the initial Zee direct testimony. Nowhere in Garrity's testimony does he specifically attack any of Zee's factual findings as to the IM plans.

(2) *Claim:* ILI and CP surveys are the "best technology." *Response:* They are very good tools when properly used but insufficient. Further, the 2016 ILI proved ILI is not always the "best." ILI does not indicate the initiation of corrosion and acceleration rate...indirect assessment and direct assessment should be utilized to have high confidence.

(3) *Claim:* Pipeline age is not a "key criterion." There are other factors that are important. *Response:* This argument is a red herring. Zee direct testimony never implied that pipeline age by itself is a concern. For aging structures past is not indication of future.

(4) *Claim:* The Morgantown leak and investigation do not support conclusion MIC is a current threat. *Response:* We do not know how much of a threat it is. The Morgantown investigation was bungled and information regarding the 75 feet of missing pipe has not been disclosed. Records of dig reports are no basis to conclude MIC is not a threat. The examination in the DNV report do show sound evidence for MIC. More testing would have confirmed.

(5) *Claim:* A massive lab testing program is not warranted. *Response:* As noted above, soil corrosivity testing and microbiological (bacterial) testing are not expensive, and they are critically important in determining the corrosiveness of the local environment of a buried pipeline.

(6) *Claim:* A remaining life assessment is not necessary. No regulations require it. The facts don't justify it. *Response:* A remaining life study for a 70-year old pipe that is poorly maintained and has experienced perforation is warranted by the facts as set out in the Zee direct testimony. The fact regulations do not require it does not preclude a judge from ordering it. Counsel advises that state law permits imposition of standards higher than federal minimums. Our tasks as responsible corrosion engineers is not to follow the minimum requirement for regulations; rather it is to do all we can to keep pipelines safe for the public.

(7) *Claim:* Evidence of wall thickness is key in deciding safety and there is no evidence of wall thickness inadequacy in this case. *Response:* The statement is both false and misleading. What is the wall thickness at a through-pit, where a leak is occurring? ~~The wall thickness was zero at the location of the leak in Morgantown.~~ Is Mr. Garrity suggesting that so long as a pipe does not leak, its thickness is adequate? It sounds that way, even though he knows better. Wall thickness problems were identified in my direct testimony. Garrity has not pointed to any of that testimony on wall thickness where my statements on thickness were inaccurate.

~~Further, in connection with the Morgantown investigation, we did not have any data from the DNV analysis or direct assessments. That includes pipeline thickness data. It should be noted we also do not know anything about the wall thickness of the missing 75 feet of ME1. We should rely on field data and not speculation for high confidence corrosion risk assessment.~~

Q. Dr. Zee, having read Mr. Garrity's rebuttal testimony, what conclusions have you reached?

A. His approach to life limiting mechanisms for aging pipelines is not based on sound corrosion engineering fundamentals. Nothing in Mr. Garrity's rebuttal testimony has caused me to change my mind. Except as noted above, the information and conclusions set out in my initial direct testimony stand.

Q. Have all of your opinions and conclusions as stated in your surrebuttal testimony regarding Messers Field and Garrity's rebuttal testimony been given to a reasonable degree of professional and scientific certainty?

A. Yes, they have. In the event that Sunoco or aligned intervenors provide additional testimony or documents, however, I reserve the right to modify my opinion or furnish additional evidence.

COMPLAINANTS OFFER SURREBUTTAL EXHIBITS ZEE – 1 THROUGH ZEE – 3 INTO EVIDENCE.