Before the
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

In the Matter of	)	
ExxonMobil Pipeline Company	)	CPF No. 4-2013-5027
Pegasus Pipeline incident	)	Notice of Probable Violation
(March 29, 2013), Mayflower, Arkansas	)	

RESPONDENT'S PRE-HEARING BRIEF

I. INTRODUCTION

On March 29, 2013, the Pegasus Pipeline, a 20" diameter pipe carrying crude oil ruptured near Mayflower, Arkansas. The pipeline is owned by Mobil Pipe Line Company, and operated by the ExxonMobil Pipeline Company (EMPCo or the Company). The pipeline was constructed in 1947-1948 and maintained under regulations promulgated by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency). The Company conducted hydrostatic pressure tests of the line at the time of construction, in 1969, 1991 and again in 2005-2006. The Company also conducted in-line inspections (ILI) of the pipe multiple times, from 1999 to 2001, again in 2010, and again from 2012 to 2013. Hydrotests and ILI are conducted to detect anomalies that could lead to failure if not remediated, but no such anomaly was ever found or reported at the point of the Mayflower rupture prior to the incident.

PHMSA issued a Notice of Probable Violation, Proposed Penalty and Proposed Compliance Order (collectively, the NOPV) to EMPCo on November 6, 2013. The NOPV set forth nine alleged violations of the Agency's integrity management program (IMP) rules, and proposed a civil penalty in excess of $2.6 million dollars and a broad compliance order. The Company contested the allegations and requested an administrative hearing on the NOPV.

The federal Pipeline Safety Act (PSA) and PHMSA's regulations implementing that statute establish a set of performance-based regulations that require pipeline operators to create their own written programs, specific to the pipeline at issue. Under the IMP rules, operators are required to prepare a written IMP plan, create a Baseline Assessment Plan (BAP), establish a schedule for hydrotest and/or ILI assessment, and, where appropriate, develop risk reduction or remediation strategies. EMPCo fully complied with the IMP rules for this line. In fact, the Company conducted more inspections of the line and implemented more risk reduction measures than are required by the regulations.

The PSA does not create a strict liability scheme, meaning that the occurrence of an incident does not automatically give rise to a violation of PHMSA regulations. In this case, PHMSA has alleged violations as if strict liability did apply; the NOPV presumes violations simply because an incident occurred. The PSA and its implementing regulations make clear that such an approach is not consistent with the applicable law. Pipeline operators, and the Agency, are expected to continually improve IMP programs as new information and new technology become available, to find and correct violations when they occur, and also to learn from incidents even where no violations exist, in order to reduce the likelihood of recurrence.

As the evidence will show, the Company complied with all applicable regulations in this instance. The anomaly that caused the Mayflower incident was not detected prior to the incident using recognized industry best practices. Accidents can occur even when an operator is in full compliance with applicable law. The PSA and its regulations acknowledge that fact, but the NOPV ignores it.

This challenge to the NOPV is not about monetary fines. The Company has already paid many millions of dollars in response to the Mayflower incident. This challenge is about the proper interpretation of the PSA, and ultimately about the proper focus in learning from an incident and working to improve pipeline integrity and public safety.

The Agency should withdraw or revise the NOPV as issued.

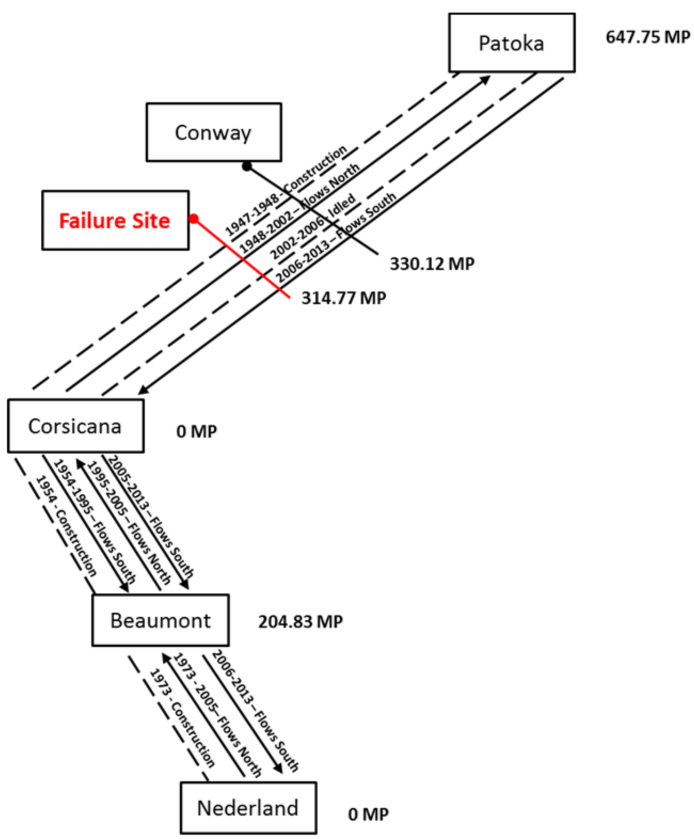
II. BACKGROUND

A. The Pegasus Pipeline System and the Mayflower Incident

The Pegasus Pipeline System consists of 859 miles of predominately 20” pipeline that transports Canadian heavy crude oil originating from Patoka, Illinois to Nederland, Texas, at which point the product is provided to Gulf Coast refineries and export marine facilities. The entire line was shut down in 2002 for market reasons, and was then reversed and restarted in 2005-2006. The system has a capacity of approximately 90,000 barrels per day and was operated at a MOP of 820 psi that was established through a 2006 hydrotest.

The system is comprised of three distinct pipeline segments that were constructed separately, with different metallurgy, manufacturer, and/or manufacturing methods, and that have been subject to different operating histories over the years. The segment at issue in this NOPV runs from Patoka, Illinois to Corsicana, Texas and was constructed in 1947-1948 from predominantly Youngstown 20” X-42/electric resistance weld (ERW) pipe, as well as some seamless pipe. *See Figure 1: Pegasus Pipeline System.*

Figure 1: Pegasus Pipeline System



On March 29, 2013, at 2:37 p.m. Central Standard Time (CST), a drop in pressure was detected in the Conway to Corsicana line segment by EMPCo’s Operations Control Center in Houston, Texas. Following receipt of a low pressure alarm (32 psig) and a pressure rate of change alarm (negative drop of 668 psig), the OCC controller began initiation of a full safe shutdown of the pipeline, which included a carefully staged shutdown of all pumps along the entire length of the pipeline and full isolation of the section of the pipeline where the release was located by closing mainline valves upstream and downstream of the rupture site. As a result, EMPCo detected the potential release, confirmed it was an actual release, and shutdown and completely isolated the affected segment within 16 minutes of the rupture.

The pressure drop resulted from a rupture of the pipeline at Milepost 314.77, causing a release of crude oil near Mayflower, Arkansas. At the time of failure, the pressure at the release site was estimated to be approximately 703 psi (below the release site MOP of 863 psi). EMPCo reported the release to the National Response Center on March 29, 2013, at approximately 3 p.m. CST (NRC Report No. 1042466), estimating that between 3,500-5,000 barrels of crude oil had been released. On April 8, 2013, EMPCo revised that estimate to 5,000 barrels.

EMPCo immediately initiated response efforts, in coordination with PHMSA, U.S. EPA, local police and other State and local agencies. The release occurred in a residential neighborhood and twenty-two homes were evacuated as part of the Company's response efforts. No injuries, fatalities or fires occurred. While the oil flowed into storm drains leading to nearby Lake Conway, a local fishing spot, no oil is believed to have reached the main body of the lake. To date, the Company has expended more than $75 million in response related costs. The line has not yet been put back in service.

B. <u>PHMSA Initial Administrative Action</u>

PHMSA issued a Corrective Action Order (CAO) to EMPCo on April 2, 2013, just three days after the release occurred. The CAO imposed four major corrective actions on the entire Pegasus Pipeline: metallurgical testing, preparation of a remedial work plan and a Restart Plan, and a pressure restriction. EMPCo requested a Hearing on the CAO, seeking to clarify or modify the Order with respect to the following: (1) the restart pressure restriction at the failure location; (2) the extent of the system subject to the CAO and the hazardous facility determination; and (3) restart pressure restrictions at other stations along the pipeline. Following the Hearing on May 2, 2013, PHMSA issued a Final Order on May 10, 2013, agreeing to amend the CAO to address the pressure issues and acknowledging that the scope of the CAO could be limited in the future depending on the results of further investigation.

C. <u>Root Cause Failure Analysis and Re-Start Plan</u>

The Root Cause Failure Analysis (RCFA) that EMPCo submitted to PHMSA on April 15, 2014, concluded that the failure was caused by original manufacturing defects, namely hook cracks along material imperfections in steel on the long seam. *Exhibit 56, EMPCo Pegasus RCFA Final Report, p. 2 (Mar. 26, 2014)*. The initial defects grew in service, over time, to critical flaw size, which resulted in the rupture. Metallurgical testing conducted by HurstLab concluded that the failure occurred:

> because of the reduction of the wall thickness in the upset zone of the Electric Resistance Weld (ERW) seam caused by the presence of manufacturing defects, namely the upturned bands of brittle martensite, combined with localized stress concentrations at the tips of the hook cracks, low fracture toughness of the material in the upset/HAZ, excessive residual stresses in the pipe from the initial forming and seam and girth welding processes, and the internal pressure creating hoop stresses.

Exhibit 55, Hurst Metallurgical Report No. 64961, p. 31 (rev. July 9, 2013). With respect to other contributing or likely contributing factors, EMPCo and industry expert John Kiefner who provided input on the RCFA identified atypical pipe properties that contributed to accelerating the propagation of cracks and the failure (*e.g.*, very high tensile strength, local high hardness, high carbon and manganese content, brittle fracture mode, residual stresses). *Exhibit 56, Appendix 3 to EMPCo Pegasus RCFA Final Report prepared by Kiefner & Associates*; *see also Exhibit 1, Kiefner Affidavit* ¶¶ 16-17, 24 (noting that the Pegasus Pipeline "exhibited highly unusual chemical and mechanical properties," "the characteristics of the pipe at the particular point of failure were unique," and that "the anomaly that caused the Pegasus incident was not capable of reliable detection give that it exhibited atypical characteristics not frequently seen before in the industry").

As required by the CAO, EMPCo continues to work with PHMSA to develop approved Re-Start Plans (RSP) for the pipeline.[1] A RSP for the portion of the line between Corsicana and Nederland, Texas was submitted to the Agency on January 31, 2014. The RSP was approved by the Agency on March 31, 2014 and plans are underway to initiate restart. The Company continues to finalize its RSP plan for the Patoka to Corsicana portion of the line before submitting it to PHMSA.

D. Issuance of NOPV, Proposed Penalty and Compliance Order by PHMSA

PHMSA issued the NOPV to EMPCo on November 6, 2013, including nine (9) Items of alleged violation, proposing more than $2.6 million in civil penalties and proposing a Compliance Order. Eight of the nine alleged violations cite to PHMSA's IMP regulations at 49 C.F.R. Part 195.452. One of the alleged violations invokes Part 195.402 (concerning Operation & Maintenance Manual requirements) but that Item also directly relates to IMP. All of the alleged violations are associated with a proposed penalty. Five (5) of the alleged violations (Items 1, 2, 5, 6 and 8) are related to the Proposed Compliance Order (PCO). EMPCo timely requested a hearing on December 6, 2013, pursuant to PHMSA regulations at 49 C.F.R. Part 190. The Hearing is scheduled for June 11, 2014.[2]

[1] Additionally, in compliance with the CAO, the Company submitted Remedial Work Plans (RWP) to PHMSA for both the Corsicana to Nederland, Texas portion of the pipeline and the Patoka, Illinois to Corsicana, Texas portion. EMPCo continues to work with the Agency to finalize the RWPs.

[2] Following the issuance of the NOPV, EMPCo requested and received on November 21, 2013, a copy of PHMSA's "Pipeline Safety Violation Report"(PSVR) (dated Nov. 6, 2013), and a copy of PHMSA's "Mayflower Failure Investigation Report" (dated Oct. 23, 2013). Neither of these documents are referred to or incorporated into the Agency's NOPV, but they provide information relied upon by PHMSA in preparing its claims in the NOPV. The documents, both of which are lengthy, contain incorrect factual information and unsupported legal conclusions that go beyond the allegations set forth in the NOPV. To the extent any such information or conclusions are relevant and material to the claims presented in the NOPV, EMPCo addresses it in its Request for Hearing pleadings (including this Brief). The Company is not addressing the entirety of the PSVR or Accident Report in this proceeding, however, and the Company denies any and all factual or legal conclusions contained in those documents.

III. APPLICABLE LAW

A. There is No Strict Liability under the PSA

It is evident that the government believes that simply *because* an incident occurred in this matter, then EMPCo must have violated the Part 195 regulations. The legal concept of strict liability supports such an approach, but it is not available here. Where strict liability does apply, an entity may be liable solely because of the occurrence of an event, without consideration of fault or cause.[3] The federal PSA has no such strict liability provision. There is nothing in the statute or PHMSA regulations implementing the statute that establishes liability for a pipeline incident without fault.

The Agency's regulations instead establish a series of performance based standards, which often incorporate various technical standards and methods. This performance based scheme is intended to provide operators with flexibility to select the most effective processes and technologies based on their specific pipeline characteristics.[4] Pipeline operators are required to follow the procedures established in this regulatory framework, and document all relevant considerations and actions taken.

Although many pipeline accidents are associated with underlying violations of PHMSA regulations (*e.g.*, operator error, failure to maintain specified records, insufficient cathodic protection, etc.), some incidents occur despite an operator's compliance with all applicable regulations. *See Exhibit 2, Muhlbauer Affidavit* ¶ 13 (noting that "[d]ue to the probabilistic nature of such scenarios, incidents can occur despite significant efforts to prevent them"). This is one such incident. Unfortunately, whether influenced by media attention or political pressure, agencies are sometimes inclined to presume violations simply because an incident occurred. The law does not support such an approach. The Agency must prove, as a matter of law, that a violation of its regulations occurred to support each of the nine items in the NOPV in this case.

B. Overview of Integrity Management Rules

When promulgating the integrity management regulations at 49 C.F.R. Part 195.452, PHMSA increased its emphasis on performance based risk management regulations. More so than any other regulations under Part 195, the integrity management rules are process oriented and allow operators a high degree of flexibility to adapt their programs and plans to fit particular circumstances. *Final Rule, 65 Fed. Reg. 75378, 75382 (Dec. 1, 2000)* ("Performance based language will best achieve effective integrity management programs that are sufficiently flexible

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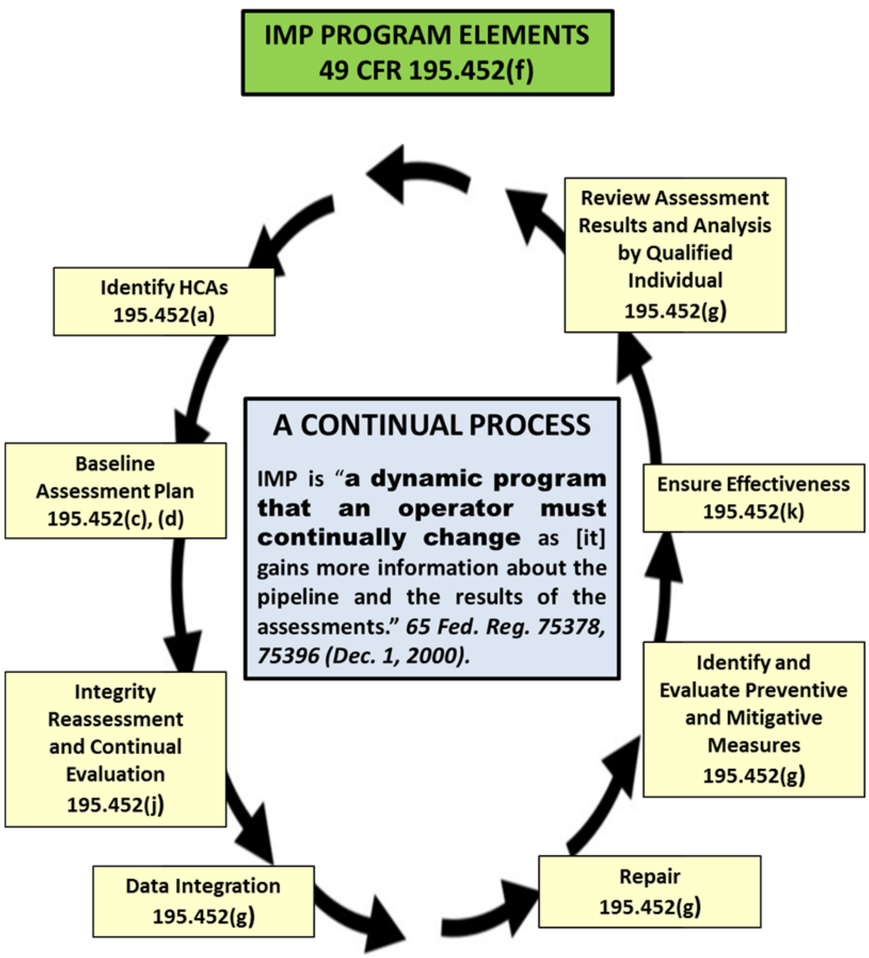
[3] An example of such a provision is found at Section 301 of the federal Clean Water Act (known as 'the discharge prohibition'), where any unpermitted release of oil to waters of the U.S. creates liability regardless of how or why the release occurred. *33 U.S.C. §§ 1311(a), as implemented through 33 U.S.C. §1321(b)(6)(A)* (authorizing assessment of administrative penalties to any "owner, operator, or person in charge" of a vessel, onshore or offshore facility from which oil is discharged); *1321(f)* (creating liability for removal costs up to finite amounts for such owners or operators and providing for increased liability where the government can show willful negligence or willful misconduct).

[4] In promulgating the original 1969 liquid pipeline regulations, which were the blueprint for the current regulations at Part 195, DOT's Hazardous Materials Regulations Board emphasized performance over prescriptive standards for the purpose of encouraging industry innovation and technological improvements. *See e.g., Final Rule, 34 Fed. Reg. 15473, 15474 (Oct. 4, 1969).*

to reflect pipeline specific conditions and risks. Performance based standards allow an operator to select the most effective processes and technologies as they become available.").

Under these rules, which first became effective in 2001, operators were required to develop a written IMP plan that included the following: (1) identification of pipelines that could affect sensitive areas called high consequence areas (HCAs); (2) a baseline assessment plan (BAP) for initial assessments of those lines; (3) procedures for the integration of all available information about pipeline integrity and the consequences of a failure; (4) prompt action to address issues identified by the assessment and prioritization of repairs; (5) reassessment at least every five years; (6) continual evaluation to include additional preventive and mitigative measures as appropriate; (7) methods to measure effectiveness; and (8) a process for review of the assessment results by a qualified individual. *49 C.F.R. Part 195.452(f); see Figure 2: IMP Program Elements.*

Figure 2: IMP Program Elements, 49 CFR Part 195.452(f)



While the rule prescribes which program components are required, its performance based elements allow operators discretion in how to implement these components. For that reason, PHMSA anticipated that this would be an evolving "dynamic" iterative process for both operators and the industry, and the agency continues to emphasize that point. *Final Rule, 65 Fed. Reg. 75378, 75386 (Dec. 1, 2000); see also PHMSA Advisory, 79 Fed. Reg. 25900, 25993*

(May 6, 2014) ("Continual improvement of IM programs (including improvements in the analytical processes involved in analyzing assessment results, identifying threats, responding to risks, the application and implementation of assessments and the development of preventative and mitigative measures) is a key aspect and critical objective of an effective IM program."). As recent statistics confirm, the performance-based integrity management rules have been successful in improving pipeline safety. Since the liquid IM regulations became effective in 2001, liquid pipeline incidents have decreased by 62%, the amount released by liquid pipelines has decreased by 47%, and liquid incidents that resulted from material defects, seam and weld failures decreased 31%. *Annual Liquid Pipeline Safety Performance Report & Strategic Plan,* prepared by AOPL and API, p. 15 (2013).

C. <u>Threat Identification and Risk Assessment under IMP</u>

A primary component of IMP is the operator's threat identification and risk assessment process which informs both the integrity assessment schedule and its method under certain circumstances. *49 C.F.R. Parts 195.452(e); 195.452(j)(5)*. The Agency requires operators to evaluate numerous risk factors for each pipeline segment, including the results of prior assessments, manufacturing information and seam type, among other factors. *49 C.F.R. Part 195.452(e)*. Based upon the results of that analysis, an operator must prioritize its segments for reassessment on a five year interval. *49 C.F.R. Part 195.452(j)(3)*. Consistent with the intent of the IMP regulations, operators are required to consider all of the regulatory risk factors in developing their assessment schedule, but they have discretion in determining the weight and risk score given to each factor and prioritization for a particular pipeline system. *See e.g., In re Magellan Midstream Partners, CPF No 4-2006-5020 (July 9, 2009)*.

The IMP rules set forth three assessment methods available to operators: (1) inline inspection or ILI; (2) hydrostatic pressure testing; and (3) external corrosion direct assessment. *49 C.F.R. 195.452(j)(5)*. For low frequency ERW (LF-ERW) or lap welded pipe *<u>that is susceptible to longitudinal seam failure</u>*, the assessment method "must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies." *Id.* PHMSA guidance clarifies that these methods include an ILI device capable of detecting seam flaws, metal loss corrosion, and deformation anomalies, or a hydrostatic test. *PHMSA Hazardous Liquid FAQ 6.10*. In addition, PHMSA guidance clarifies that evaluation of seam susceptibility "can involve a variety of factors such as original pipe purchase specifications, incident history, operating pressure, prior pressure testing, pressure cycling, etc." *PHMSA Hazardous Liquid FAQ 6.11(a).* PHMSA guidance also notes that a process should be in place to reevaluate this determination on an appropriate interval if any factors have the potential to change. *Id.* Beyond this, PHMSA has not promulgated any additional requirements or guidance associated with integrity management requirements for LF-ERW pipe.

An Agency-commissioned report was released in 2004 to address how an operator should assess whether LF-ERW pipe is susceptible to seam failure. *See Michael Baker and John Kiefner, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation (2004) (Baker/Kiefner Report).* This report was largely based on a 2002 report issued by Kiefner, entitled *Dealing with Low Frequency Welded and Flash Welded Pipe with Respect to HCA Related Integrity Assessments (2002)*. While the evaluative process described in these reports is not incorporated into the regulations, it has been endorsed by the Agency through subsequent enforcement and referenced in the Agency's enforcement manual.[5] Specifically, the process considers pipe and seam characteristics, in service and hydrostatic test failures, the cause of those failures, operating stress level, fracture toughness, fatigue crack growth rate characteristics and the nature of operational pressure cycles on the pipeline. This data is then applied to determine whether a given segment of LF-ERW pipe is susceptible to seam failure. *Id. at p. 18 (Figure 4.1.);*[6] *see also Exhibit 3, Baker/Kiefner Report Figure 4.1.*

For the reasons noted above, and contrary to PHMSA's assertions in the NOPV and Pipeline Safety Violation Report (PSVR), all LF-ERW pipe is ***not*** presumptively susceptible to seam failure. PHMSA law and guidance requires consideration of seam failure susceptibility, but it does not require a presumptive conclusion of susceptibility where the pipeline has been subjected to a hydrostatic test and an engineering analysis indicates that there is no evidence of pressure cycle fatigue, preferential seam corrosion, or other time dependent defects.

D. Discovery, Mitigation and Risk Reduction

After carrying out an integrity assessment, PHMSA regulations require that operators validate the results of an integrity assessment, account for ILI tool tolerances, and integrate all available data regarding the pipeline. *49 C.F.R. Part 195.452(g); PHMSA Hazardous Liquid IMP FAQ 7.19* ("tool tolerance should be considered as part of the data integration process" as well as prior excavations, digs, and inspections). Factoring in that analysis, operators "discover" integrity conditions when they have adequate information about the condition to determine whether an anomaly exceeds the criteria established in the IMP regulations. *49 C.F.R. Part 195.452(h)(2).*[7] This must occur promptly, but no later than 180 days after an assessment unless that period is impracticable, allowing for flexibility because discovery varies depending on the circumstances. *Final Rule, 65 Fed. Reg. 75378, 75384 (Dec. 1, 2000)* (noting that discovery may occur when an operator receives the preliminary ILI report, gathers and integrates information from other inspections or periodic evaluations, excavates the anomaly or receives the final internal inspection report); *see also PHMSA Hazardous Liquid IM FAQ 7.3*.

Once operators declare discovery, they must timely remediate and repair integrity conditions that exceed regulatory criteria based on a prioritized schedule. *49 C.F.R. Part 195.452(h)(3)-(4).* While some conditions require immediate repair, others must be scheduled within 60 days of

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[5] *In re Kinder Morgan Energy Partners, CPF No. 1-2004-5004 (June 26, 2006)* (noting that Kiefner's methodology is an example of an acceptable means of performing a seam failure susceptibility analysis); *see also PHMSA Hazardous Liquid IM Enforcement Guidance p. 131 (Sept. 17, 2013).*

[6] Notably the Baker/Kiefner Report explains that Figure 4.1 "represents a decision tree that allows one, by supplying appropriate data on a given segment, to determine if a seam-integrity assessment is required *based on the federal pipeline integrity management regulations*" and that "baseline assessment in the form of a hydrostatic test demonstrates a level of serviceability consistent with the test-pressure to operating pressure ratio the operator selects. Additional information may be derived from the examination of test leaks or breaks if any occur. Remaining life after the test can be assessed from the standpoint of pressure-cycle induced fatigue. *The results of the test are expected to provide sufficient information for the operator to decide whether or not the pipeline is susceptible to seam failure in the context of the federal regulations pertaining to pipeline integrity management* (49 C.F.R. 195.452)." *Baker/Kiefner Report*, pp. 16-17 footnote 3 *(emphasis added).*

[7] PHMSA guidance clarifies that where tool run data is suspect and an entire rerun is performed, the evaluation will be expected within 180 days of the successful tool run. *PHMSA Hazardous Liquid IMP FAQ 4.13*.

discovery, 180 days, or later under certain circumstances. *49 C.F.R. Part 195.452(h)(4).* PHMSA guidance clarifies that "immediate" repair means that repairs must be effectuated "as soon as practicable." *PHMSA Hazardous Liquid FAQ 7.4*.

In addition to performing required repairs, operators must conduct a risk analysis regarding whether additional preventive and mitigative (P&M) measures are warranted to mitigate the consequences of a failure that could affect an HCA. *49 C.F.R. Part 195.452(i)* (evaluating the likelihood of a pipeline release and how it could affect the HCA based on all relevant risk factors). Specific P&M measures mentioned in the regulations include establishing shorter inspection intervals and installing emergency flow restrictive devices (EFRDs), among others. *49 C.F.R. Part 195.452(i)(1).* There is, however, no regulatory timeframe associated with implementing P&M measures, and PHMSA has acknowledged that this time period is highly dependent on the proposed P&M measure, noting that while some measures can be implemented quickly, others require significant time for budgeting, engineering and design. *PHMSA Hazardous Liquid IMP FAQ 9.9* ("because of this wide disparity, there is no fixed time requirement for implementing preventive and mitigative actions").

IV. <u>NOPV ITEM BY ITEM ARGUMENT</u>

The issues as joined in this proceeding present questions of law under the Pipeline Safety Act and its implementing regulations at 49 C.F.R. Part 195. The NOPV contains nine claims of alleged violation of law. The Respondent's Request for Hearing contests each of those allegations, asserting that it is possible for pipeline accidents to occur even when an operator is in compliance with the applicable law.

The material facts of the incident, and actions leading up to the incident, are largely undisputed. For the majority of the NOPV Items (Items 1 – 4, 7 and 8), there is no issue of material fact. For those Items, the only potential questions of mixed law and fact can be summarized as follows:

> (1) did the Company conduct a risk assessment that considered LF-ERW seam failure susceptibility, as required by Part 195.452(e)?
>
> (2) did the Company conduct a risk ranking of the pipe segment at issue, as required by Part 195.452(j)(2)?
>
> (3) were the various tools and inspection methods that were employed prior to the incident, as required by Part 195.452(j)(5), designed to reliably detect the anomaly that existed?

As the record reflects that the answer to the above questions is in the affirmative, but the Agency has not provided adequate reasoning to justify its approach to these questions. As the record and exhibits establish, the Company did conduct a risk assessment that considered the risk of seam failure, as well as appropriate risk ranking using all available information. The record also shows that the anomaly at the point of rupture was not detected by the multiple inspection methods and tools employed prior to the incident.

The remaining allegations in NOPV Items 5, 6 and 9 are based upon mistakes of fact, as is demonstrated by record evidence, and therefore cannot be sustained. With all of these factual issues clearly established by the record, only legal questions remain, all relating to the proper implementation of the Agency's authority under the PSA and the application of the plain language of its regulations.

NOPV ITEM 1: Alleged Failure to Consider Risk of Seam Failure on ERW Pipe

In Item 1 of the NOPV the Agency alleges that the Company did not consider seam failure susceptibility as a risk factor in its IMP program as required by 49 C.F.R. Part 195.452(e)(1). The record clearly shows that the Company did expressly consider seam failure susceptibility for ERW pipe and documented those analyses. Thus, although not stated as such, the NOPV is actually alleging that the Company violated the IMP requirements by not concluding that the pipe was susceptible to seam failure.

This distinction in how the NOPV is drafted is significant. The Agency's IMP regulations do not dictate the conclusion that an operator should reach in following the threat identification and risk assessment process required by Part 195. To the contrary, the regulations require only that an operator fully *consider* all applicable threats, and document that process. EMPCo did just that. The fact that the Company did not *conclude* that the pipe was susceptible to seam failure does not give rise to a violation of applicable law.

Roughly one-fourth of all oil pipelines in the U.S. are LF-ERW.[8] The Agency's approach to consideration of LF-ERW pipe as stated in the NOPV does not follow PHMSA's own rules or precedent. As articulated in this proceeding, PHMSA's approach to LF-ERW pipe would have a significant adverse impact on public safety and energy transportation.

Initial Seam Failure Analyses and Integrity Assessment

EMPCo's written IMP Baseline Assessment Plan was first prepared in 2001 and its IMP plan was finalized in 2002, in close consultation with leading industry experts, such as John Kiefner and Kent Muhlbauer. *Exhibit 1, Kiefner Affidavit* ¶ 10; *Exhibit 2, Muhlbauer Affidavit* ¶ *6*. The IMP plan has been reviewed annually and updated over time (with continuing input from Kiefner and Muhlbauer), to reflect changes in the regulations, and to incorporate industry guidance and lessons learned from operation of the EMPCo system. *Id.; see also Exhibit 2, Muhlbauer Affidavit* ¶ 7 (noting that EMPCo's IMP manual "is among the most complete and well-written of any such manuals I have seen"). The Company's IMP program has also been reviewed by PHMSA on multiple occasions (2003, 2007 and 2011), including an in-depth review of the Pegasus system specifically in 2007. The Company addressed all concerns noted by the Agency in those reviews, through further revisions to its IMP plan.[9]

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[8] *PHMSA, Hazardous Liquids Annual Data 2012 (as of May 1, 2014) available at* www.phmsa.dot.gov, (as set forth in annual operator reports submitted in 2013 for the year 2012 and including direct current welded pipe).

[9] As a result of the Agency's 2011 inspection, PHMSA cited EMPCo for violations of Part 195 for which a Petition for Reconsideration is pending. *PHMSA Final Order, CPF No. 4-2011-5016 (June 27, 2013)*. As part of that action, PHMSA issued a Compliance Order with two items. Item 1 of the Compliance Order has been stayed pending a decision on the Petition, and EMPCo timely submitted revised procedures under Item 2 of the Compliance Order to the Southwest Region on August 1, 2013. PHMSA Inspector John Pepper responded to the proposed revisions requesting additional modifications on August 5, 2013; EMPCO addressed those in a further revised version submitted to PHMSA on August 29, 2013. To date, the Company has not heard back from PHMSA on those revisions or its Petition for Reconsideration.

In compliance with the above regulatory requirements and guidance, EMPCo developed a process for analyzing seam failure susceptibility in reliance on the Kiefner and Baker Reports[10] and in consultation with Kiefner himself. *Exhibit 1, Kiefner Affidavit,* p. 2 ¶¶ 11-12. Kiefner created the Pipelife software for the industry at the request of EMPCo to use in analyzing pressure cycling induced fatigue. *Id.* The results of this analysis were expressly considered in EMPCo's Threat Identification and Risk Assessment (TIARA) software inputs, which identify IMP threats and the relevant risk score of a pipeline segment. *Exhibit 13, EMPCo TIARA Foreman to Conway UDT Q&A (6/26/06).* All results were then considered in developing reassessment schedules.

EMPCo first evaluated the pipeline's susceptibility to longitudinal seam failure in late 2004 and early 2005, as the Pipelife software and Baker Report became available. *Exhibit 8, EMPCo Memo regarding Corsicana to Patoka LSFSA (Dec. 10, 2004); Exhibit 9, Memo regarding Corsicana to Patoka LSFSA (Feb. 10, 2005)*; *see Figure 3 EMPCo IMP Assessment and LSFSA: Conway to Foreman.* The Company's 2004-2005 evaluations of the Pegasus Pipeline included consideration of pressure cycling induced fatigue and concluded that the pipe was not susceptible to seam failure. *Id.* Because the line had been idled from 2002-2005, the Company conducted a baseline assessment hydrostatic test in 2005-2006. Following the process developed by Kiefner and reflected in the Baker Report, the failures that occurred during the hydrotest were subsequently repaired and analyzed by an expert metallurgist for evidence of pressure cycling induced fatigue and preferential seam corrosion. *Exhibits 12 and 15, EMPCo Excerpts of Metallurgical Analyses performed by HurstLabs (2006)*; *Exhibit 14, EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (July 6, 2007)*. The results of those analyses did not indicate the presence of either condition. *Id.*

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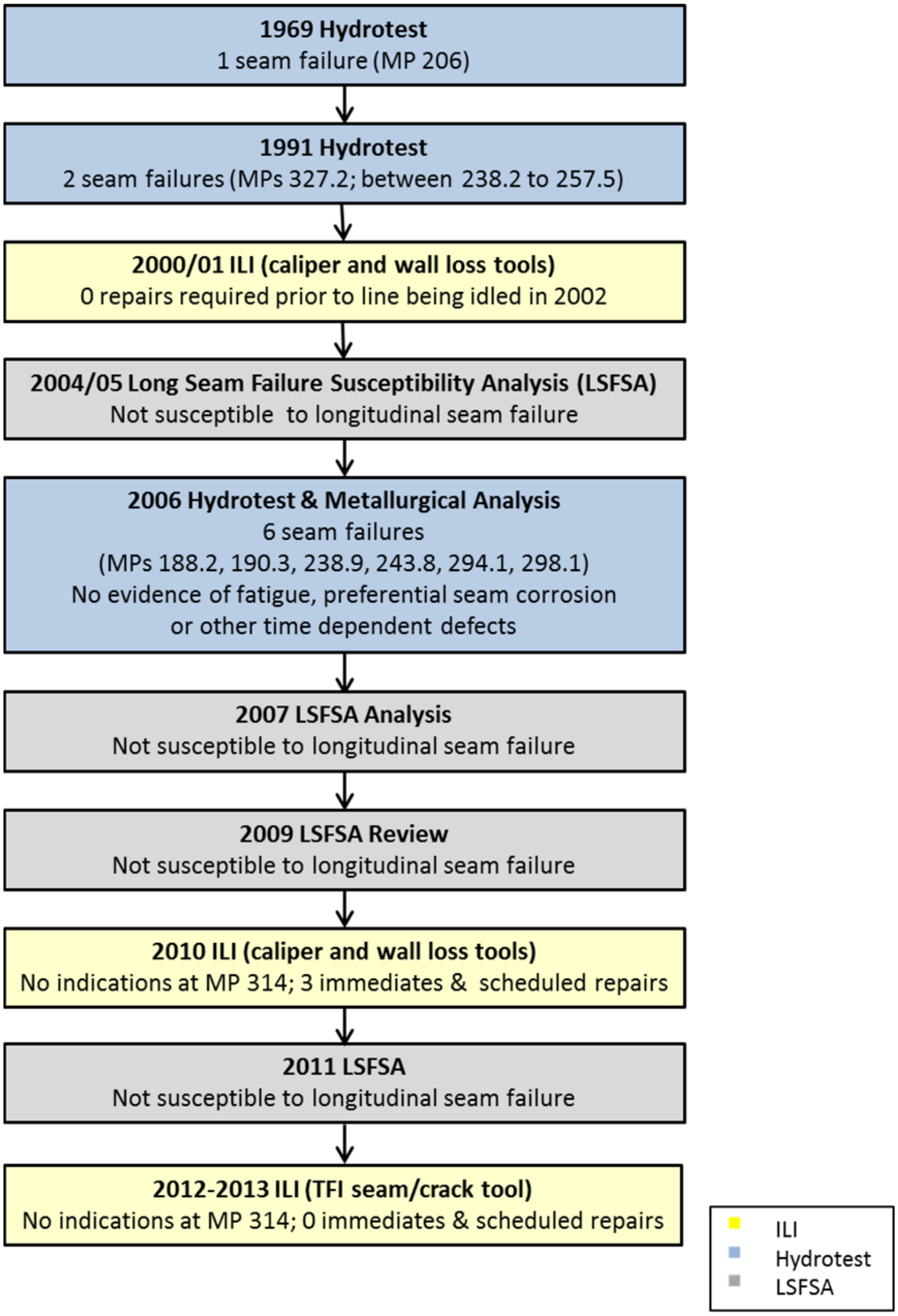
[10] EMPCo has reviewed and updated this process numerous times since its inception, including incorporating updated versions of the Pipelife software, revising the LSFSA analysis, sharing metallurgical findings with Kiefner and Associates in support of industry studies, performing a companywide fatigue screening for all LF-ERW pipelines, and developing a SCADA-based system to detect pressure cycling tends with the potential to shorten the theoretical fatigue lives, among other updates.

Figure 3

EMPCo Integrity Assessment and LSFSA Analysis: Conway to Foreman (prior to March 29, 2013 Mayflower Incident at MP 314.77)



In planning the next integrity reassessment for 2010, the Company's TIARA software accounted for the seam type, history and the long seam failure susceptibility analysis (LSFSA), among other inputs. *Exhibit 13, EMPCo TIARA Foreman to Conway UDT Q&A (June 26, 2006)*. Again, that evaluation did not identify manufacturing or other seam-related threats to the Pegasus Pipeline. *Exhibit 17, EMPCo TIARA Foreman to Conway Manufacturing Threat Classification (July 26, 2006); Exhibit 18, EMPCo TIARA Foreman to Conway Risk Assessment Summary (July 27, 2006)*.

Subsequent Seam Failure Susceptibility Analyses and Reassessment

In 2007, EMPCo performed another LSFSA of the Pegasus Pipeline. *Exhibit 21, EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)*. Once again, the evaluation concluded that the line was not susceptible to long seam failure.[11] *Id*. The Pipelife fatigue analysis created (and applied in this instance) by Kiefner indicated that the Conway to Foreman segment of the line had a remaining fatigue life of over 373 years and a 180 year reassessment interval.[12] *Id.; Exhibit 1, Kiefner Affidavit* ¶ 14 (stating that the Pegasus Pipeline "appeared to have a theoretical fatigue life in excess of the conservative reassessment interval implemented by EMPCo"). In 2009, after two years of operation and a planned expansion of the pipeline throughput, the Company again reviewed its 2007 long seam failure analysis as well as the metallurgical failure analyses, in preparation for a scheduled 2010 IMP reassessment of the line. *Exhibit 21, EMPCo Patoka to Corsicana LSFSA Review (2009)*; *see also see Figure 3 EMPCo IMP Assessment and LSFSA: Conway to Foreman.*

The Company did run an ILI tool in 2010, although not a seam or crack tool. *Exhibit 50, Final ILI Report Conway to Corsicana (2010)*; *see also Figure 3, EMPCo Conway to Foreman IMP Inspection History*. While the analysis of seam susceptibility did not change, the Company also decided to schedule an ILI TFI seam/crack tool run on the Patoka to Conway section of the line. *Exhibit 29, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpts (2011)*; *Exhibit 35, EMPCo Conway to Corsicana IMP IAD Form 3.2 (Mar. 15, 2011)*. That decision was made to further evaluate the very risk factors that PHMSA now alleges were 'not considered' by the Company. Subsequent long seam failure susceptibility analyses performed in 2011 indicated that the Conway to Corsicana segment of the line still had over 20 years of remaining theoretical fatigue life.[13] *Exhibit 29, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpts (2011); Exhibit 1, Kiefner Affidavit* ¶ 14. Even though it was not required under the regulations, EMPCo assessed the Corsicana to Conway section of the line with a TFI seam/crack tool in 2012 and 2013. *Exhibit 54, EMPCo Conway to Corsicana GE PII TFI Final ILI Report (2013)*. As

[11] *Exhibit 1, Kiefner Affidavit,* ¶¶ *13;19* (noting that "it is reasonable to certify that hydrostatic test failures are not an indication that the pipeline is susceptible to seam failures in the context of Part 195 IMP regulations" where there is no evidence of fatigue related crack growth, selective seam corrosion or other time dependent defects, and explaining that EMPCo's conclusion in this instance was reasonable).

[12] Specifically the Foreman to Conway section of the Pegasus Pipeline had a theoretical fatigue life of 373 years and a reassessment interval of 186.6 years (with a safety factor of 2) with extremely light pressure cycling. *Exhibit 21, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpt (2007).*

[13] This analysis indicated that the Conway to Corsicana segment had 21.8 years of theoretical fatigue life and a reassessment interval of 10.4 years with light pressure cycling. *Exhibit 29, EMPCO Conway to Corsicana LSFSA and Pipelife Excerpts (2011).*

discussed in the preceding sections of this brief at the ultimate point of rupture was discovered reported by the ILI vendor.

EMPCo Exceeded the Minimum IMP Requirements

As made evident by the above actions (documented in the record and attached Exhibits), EMPCo clearly <u>*did*</u> consider the threat of long seam failure on LF-ERW pipe in the Pegasus Pipeline system. *Exhibit 2, Muhlbauer Affidavit* ¶¶ 8, 11-12. Industry expert John Kiefner stated that the Company's conclusion that the failure segment was not susceptible under the federal regulations was reasonable and consistent with available guidance prior to March 29, 2013 and that seam-integrity assessment activities employed on the segment were consistent with the IMP regulations and guidance. *Exhibit 1, Kiefner Affidavit* ¶¶ 19, 21. In undertaking those evaluations, the Company did <u>*more*</u> than the minimum required by IMP rules, not less. *Exhibit 2, Muhlbauer Affidavit* ¶¶ 6-7 (noting that EMPCo's IMP manual "is among the most complete and well-written of the many such manuals I have seen"). Moreover, the Company's IMP plan, procedures and outputs were developed and applied in close consultation with industry experts often used and relied upon by PHMSA, even in the NOPV documentation presented in this proceeding. *See e.g., Exhibit 1, Kiefner Affidavit* ¶10.

PHMSA regulations require pipeline operators to consider risk factors such as susceptibility to seam failure, but they do not require that an operator conclude such a risk exists simply because LF-ERW pipe is present. In this instance, EMPCo clearly did consider seam failure as a risk, and it repeated that evaluation process multiple times, eventually running a seam/crack ILI tool that the Agency alleges should have been run if the Company *had* concluded that a risk of seam failure was present. The seam/crack ILI tool did not identify any actionable anomaly.

The allegations in Item 1 of the NOPV are incorrect, and the alleged violation should be withdrawn.

<u>***NOPV Item 2: Alleged Failure to Establish Five Year Reassessment Interval***</u>

In Item 2, PHMSA alleges that EMPCo failed to establish a five year reassessment interval pursuant to 49 C.F.R. Part 195.452(j)(3). That allegation hinges on the Agency's assertion in NOPV Item 1 that the Company should have determined that the Pegasus Pipeline was susceptible to seam failure. The NOPV asserts that the Company should have concluded, on the basis of the 2005 and 2006 BAP hydrotests, that the line was in fact susceptible to seam failure and should have established a five year reassessment interval. As discussed above in response to Item 1, the Company did carefully consider the 2005–2006 hydrotest data with regard to the risk of seam failure. The Company also consulted with both Kiefner and Muhlbauer on these issues. *Exhibit 1, Kiefner Affidavit* ¶¶ 11-12; *Exhibit 2, Muhlbauer Affidavit* ¶ 6. The conclusion from that review was that there was no evidence of either pressure cycling induced fatigue or preferential seam corrosion. *Exhibit 14, EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (July 6, 2007)*; *Exhibit 21, EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)*; *see also Exhibit 1, Kiefner Affidavit* ¶¶ 19, 21.

Because the Company's analysis of seam failure susceptibility concluded that the Pegasus Pipeline was not susceptible under the federal regulations, there was no requirement under IMP to schedule a seam tool. Thus, the Company did not violate the requirement to establish a five year reassessment interval for a seam or crack ILI tool.

The Agency's allegations in Item 2 of the NOPV can only have relevance if the allegations in Item 1 are deemed correct. Since the Company clearly *did* consider the risk of seam failure susceptibility (Item 1) and concluded that the risk was not significant, then there was no requirement to establish a five year interval to reassess the risk not found (Item 2). PHMSA's allegations therefore fail in both Item 1 and Item 2. Because the pipeline was not determined to be susceptible to seam failure in accordance with applicable law and guidance, no seam/crack tool inspection was required to be performed on five year intervals.

Ironically (in light of the allegations of the NOPV), the Company did run a seam ILI tool to further evaluate the potential risk of seam failure, even though it was not required to do so. And the Company continued to review its reassessment and tool type schedules based on pressure cycle fatigue calculations using the Pipelife software developed for EMPCo by Kiefner. *Exhibit 1, Kiefner Affidavit* ¶¶ 19, 21 (noting that EMPCo's activities were consistent with the regulations and the Baker Report flow chart). As explained in the Baker/Kiefner Report:

> If no fatigue-related failures exist, it is reasonable to certify that the pipeline is not susceptible to seam failures in the context of federal integrity management requirements. This does not, however, necessarily preclude the need for periodic reassessment. A reassessment interval should be calculated using the best available information. As more information is gained and new tools developed, the need for and timing of future reassessments can be re-evaluated.

Baker/Kiefner Report, p. 26; *see also Exhibit 1, Kiefner Affidavit* ¶ 13 (noting that if there is no evidence of fatigue related crack growth, selective seam corrosion or evidence of other time dependent defects such as stress corrosion cracking, "it reasonable to certify that the hydrostatic test failures are not an indication that the pipeline is susceptible to seam failures in the context of the Part 195 IMP regulations"). In doing all of this, the Company was expressly going beyond the regulatory requirements, in keeping with the Agency's directive that an operator's integrity management program should be a dynamic and iterative process.

The allegations in Item 2 of the NOPV are incorrect, and the alleged violation should be withdrawn.

NOPV ITEM 3: Alleged Failure to Follow IMP Plan Procedure

In Item 3 of the NOPV, the Agency alleges that EMPCo failed to follow its own IMP procedure found at Section 5.1 of its IMP Manual. That procedure implements the requirements of Part 195.452(j)(3), to provide for "continual evaluation and assessment" of pipeline segments subject to IMP. The NOPV specifically alleges that the Company improperly changed the timing of a planned ILI for the pipeline, extending it from "prior to [the end of] 2011" to late 2012 or early 2013, without providing advance notice to PHMSA.

As discussed in response to Items 1 and 2 above, the Company properly followed the IMP regulations by considering whether the pipe at issue was susceptible to long seam failure, in compliance with 49 C.F.R. Part 195.452(e)(1). This consideration was fully documented, and included input and review by John Kiefner, whom the Agency recognizes as a national expert and who created the PHMSA-endorsed process for evaluation of LF-ERW longitudinal seams under IMP.

Following its IMP procedure, the Company concluded that the pipe segment was not susceptible to seam failure in 2007, 2009 and again in 2011. PHMSA reviewed EMPCo's IMP procedures and LSFSA analysis on multiple occasions (2003, 2007 and 2011), including an in-depth review of the Pegasus system specifically in 2007, and did not raise any concerns.[14] As a result of the Company's determination that the line was not susceptible to seam failure, no seam reassessment was required. Based on the 2010 ILI on the segment at issue and subsequent risk analysis, the next required integrity reassessment date was July of 2015. The Company nevertheless elected to run a seam tool ILI well in advance of that date, which was not required by the rules because the pipe was not deemed susceptible to seam failure. As this tool run was not required, it was not subject to the variance reporting requirements at 49 C.F.R. Part 195.452(j)(5) or EMPCo's IMP manual. *See Exhibit 4, EMPCo IMP Manual Excerpts Section 5.1(4) Continual Evaluation*. The seam/crack tool ILI was voluntarily run in advance of the incident, but no actionable anomaly at the point of rupture was reported by the ILI vendor.

The fact that the Company elected to use the seam/crack ILI tool even though it was not required illustrates EMPCo's diligent and proactive approach, and willingness to go beyond minimal requirements. The ILI tool that the Agency insists should have been run was, in fact, run well in advance of the required reassessment interval, and before the incident occurred. Because it was a discretionary tool run, there was no requirement to provide written notice to the Agency or complete a Management of Change (MOC) document and the Company was free to modify its internal schedule for such a discretionary action. The Company *did* meet the reassessment intervals for ILI referenced by PHMSA and it *did* voluntarily run a seam tool even though not required. Most significantly, that tool run did not report any actionable anomaly, which further supports the fact that the Agency's complaint in this Item is both unfounded and irrelevant.

The allegations in Item 3 of the NOPV are incorrect, and the alleged violation should be withdrawn.

NOPV Item 4: Alleged Failure to Prioritize Pipeline Segments for Reassessment in Integrity Assessment Schedule that Posted Highest Risk to HCAs

The Agency alleges in Item 4 of the NOPV that the Company failed to prioritize the Pegasus Pipeline segments that posed the highest risk to high consequence areas (HCAs) before reassessing lower risk segments. Citing 49 C.F.R. Parts 195.452(e) and (j)(3) again, the Agency alleges that EMPCo failed to prioritize the Corsicana to Conway segment higher than the Patoka to Conway segment for reassessment related to manufacturing flaws and seam failure susceptibility. The record clearly shows, however, that the Company *did* carefully consider all identified risk factors in planning the reassessment intervals for the Pegasus Pipeline and that those considerations were well documented.

The Company properly followed the IMP regulations by considering all risk factors reflecting the risk conditions on the segments as required under 49 C.F.R. Parts 195.452(e) and 195.452(j)(3). *See Exhibit 2, Muhlbauer Affidavit* ¶¶ 11-12 (stating that EMPCo "properly recognized the issues associated with LF-ERW pipe, reacted to the threats on the Pegasus pipeline, and complied with the Part 195 IMP regulations"). EMPCo's risk assessment process was drafted with input and review from Kent Muhlbauer, a nationally recognized expert on

[14] As discussed supra at p. 11.

pipeline risk management. *Exhibit 2, Muhlbauer Affidavit* ¶¶ 6-7. As discussed above, the IMP rules *do not* mandate how operators assign risk scores to each risk factor or how they prioritize assessments, but require that operators consider the regulatory factors and conduct a meaningful analyses of their particular systems.

As described above, following its IMP procedures, the Company's risk assessments and evaluation did not identify long seam failure susceptibility or manufacturing as risks to either the Patoka to Conway or Conway to Corsicana segments. *Exhibit 19, EMPCO Risk Assessment Summaries for Patoka to Corsicana (2006)*. Further, the 2007 risk scores on both segments were practically identical.[15] Even though it was not required under Part 195 or EMPCo procedures, when planning the reassessment tools in 2009, the Company made the decision to assess the Patoka to Conway segment with a TFI seam/crack tool. This decision was based on the fact that, as compared to the Conway to Corsicana segment, the Patoka to Conway segment experienced more hydrostatic seam failures on a LF ERW per mile basis, more pressure reversals, and shorter fatigue lives based on 2007 data.[16] *Exhibit 22, EMPCO Patoka to Corsicana LSFSA Review (2009)*. In addition, the Patoka to Conway segment experienced three girth weld leaks that were not present on the Conway to Corsicana segment.

As with Items 1-3 of the NOPV, Item 4 is based on an inaccurate and improper assumption and should be withdrawn. The Company considered seam susceptibility many times, and concluded that no significant risk was present. Given such well-documented and careful consideration of all known risk factors, there was no legal requirement to run a seam/crack tool, there was no obligation to schedule a five year reassessment interval of a tool not required, and there was no requirement to prioritize one segment differently than another. A seam tool was voluntarily run, resulting in no reported anomalies at the point of failure.

NOPV Item 5: Alleged Failure to Take Prompt Action to Address All Anomalous Conditions by Not Declaring Discovery of Immediate Repair Conditions

PHMSA alleges that EMPCo failed to declare discovery of immediate repair conditions from information received in preliminary reports from the ILI vendor, and, as a result, treated "Immediate Conditions" as "Validation Digs" or "Confirmation Digs." The Agency argues that this failure led to a violation of 49 C.F.R. Part 195.452(h) because EMPCo failed to take appropriate action for "Immediate Conditions." PHMSA claims that EMPCo received a preliminary report on August 9, 2010, identifying two "Immediate Conditions" at MP 164.051 and MP 142.394. The Agency further alleges that MP 164.051 was not addressed until August 28, 2010, and that MP 142.394 was not addressed until several months after the report on January 6, 2011. PHMSA's allegations are unfounded, and based on incorrect factual assumptions and conclusions.

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[15] The TIARA risk scores on the Patoka to Conway and Conway to Corsicana segments in 2006 were roughly the same, both in the D3 range on the EMPCo IMP Risk Matrix. Pursuant to the EMPCo Risk Matrix Methodology, a score of D3 estimates that the probability of an event is very unlikely and that the consequences of an event may include restricted work or medical treatment and/or potential short term or minor adverse environmental impacts, among other consequences. *Exhibit 6, Attachment #1 to EMPCO OIMS System 2A.* For this risk category, there are no further (P&M) actions to consider. *Id.*

[16] The EMPCo 2011 fatigue analyses cited in the NOPV were not performed until after the 2010 assessments were completed.

In the first instance, the anomaly at MP 164.051 was identified as a 72% external metal loss call in a preliminary report dated and received by the Company on August 23, 2010. *Exhibit 23, EMPCo Email from NDT (8/23/10)*; *Exhibit 24, EMPCo NDT Preliminary ILI Report (Aug. 23, 2010)*. PHMSA's erroneous allegation that the report was received on August 9, 2010, is based on the date of an underlying dig sheet maintained by the vendor, <u>not</u> the date the preliminary report was received by EMPCo. Ironically, PHMSA correctly notes the receipt of the preliminary report in the Table included in NOPV Item 6 (last line, second column). The Company factored in tool tolerance and declared discovery of this anomaly as a potential immediate repair on <u>*the same day*</u> it received the preliminary report, August 23, 2010. The anomaly was repaired just five days later, on August 28, 2010. *Exhibit 25, EMPCo Repair Form PL-0751 (Aug. 28, 2010)*.

EMPCo became aware of the second anomaly, MP 142.394, in the *final* report received by the Company from the vendor on January 10, 2011.[17] *Exhibit 30, Email from NDT and MP 142.39 Dig Sheet (Jan. 10, 2011).* This anomaly was not identified in any preliminary report. The anomaly was found to be a 0.74% top dent with an external corrosion pit, believed to be associated with original construction. The Company acted within <u>two days</u> of receiving the final report, repairing the anomaly on January 12, 2011. *Exhibit 31, EMPCo Repair Form PL-0751 (Jan. 12, 2011).*

The factual basis for the allegations in NOPV Item 5 are simply inaccurate and the suggestion of any violation is without foundation and should be withdrawn. As set forth above and reflected in the record, EMPCo complied with the discovery deadline for "Immediate Conditions" set forth by the applicable regulations in both instances cited by PHMSA.

<u>***NOPV Item 6: Alleged Failure to Declare Discovery of Condition within 180 Days***</u>

In Item 6 of the NOPV, PHMSA alleges that EMPCo failed to declare discovery within 180 days on four separate occasions on the Patoka to Corsicana segments of the Pegasus Pipeline in 2010, 2011 and 2013. PHMSA specifically asserts that EMPCo had sufficient information from the ILI vendor to make such determinations, again citing to 49 C.F.R. Part 195.452(h). To the contrary, the record confirms that in all instances the tool vendor did not provide EMPCo with the ILI data until nearly the conclusion of the 180-day period, making it impracticable to declare discovery within the 180 day timeframe. *Exhibit 26, EMPCo IMP Form 1.2 (Dec. 17, 2010); Exhibit 33, EMPCo IMP Form 1.2 (Jan. 31, 2011); Exhibit 38, EMPCo IMP Form 1.2 (Aug. 2, 2013); Exhibit 39, EMPCo IMP Form 1.2 (Aug. 28, 2013)*. Consistent with IMP regulations, the Company's IMP Manual provides that discovery is required within 180 days of running the ILI tool, unless there are circumstances that make discovery impractical. *Exhibit 4, EMPCo IMP Manual Excerpts Section 4.4 Timeliness of Discovery; 49 C.F.R. Part 195.452(h)(2).* Until the Company can verify the ILI vendor data and complete data integration, the Company does not have sufficient information to declare discovery. The Company followed its procedure, as established in its IMP Manual, to extend the 180-day timeframe with adequate justification. *See Figure 4, Summary of Discovery Dates for ILIs Referenced in PHMSA NOPV.*

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[17] The PHMSA PSVR includes as support a PL-0751 repair form associated with a <u>*different*</u> immediate anomaly located at MP 274.091 and odometer number 296278.97. This anomaly was discovered when EMPCo received the final ILI report on January 10, 2011 and was repaired on January 13, 2011 (when the inspector signed the repair form). *Exhibit 32, EMPCo Repair Form PL-0751 MP 274.09 (Jan. 13, 2011).*

Figure 4: Summary of Discovery Dates for ILIs Referenced in PHMSA NOPV

ILI Tool (date completed)*	Date of Final Report	Date(s) of IMP Form 1.2 Extension Request	180 Day Deadline	Date of Discovery	Revised Deadline**
Patoka to Conway					
MFL-Combo and TFI (8/15/10)	12/30/10	1/31/11	2/11/11	3/4/11	**3/11/11**
Conway to Corsicana					
MFL Combo (7/21/10)	1/7/11	12/17/10	1/17/11	3/15/11	**3/17/11**
TFI (2/6/13)	8/29/13	8/2/13; 8/28/13	8/5/13	10/7/13	**10/7/13**

*This is the date the last tool entered the receiving trap.
**Exception approved due to delayed receipt of final ILI vendor report.

The Agency's allegations in this instance are unfounded, given that the Company followed its procedures and the IMP regulations. Moreover, it is peculiar that PHMSA would allege this violation given that the Agency has not even responded to EMPCo on proposed revisions to its IMP Manual on this very issue of whether an operator has sufficient information to declare discovery.[18]

NOPV Item 7: Alleged Failure to Follow Procedure for Updating Risk Assessments as Changes Occur

PHMSA alleges in Item 7 that EMPCo did not follow internal procedures IMP 5.4 and OIMS 2.4 regarding updating risk assessments in response to potential threat changes, citing again to 49 C.F.R. Parts 195.452(b)(5) and (j). The Agency argues that EMPCo should have updated its risk assessment when the Company extended the inspection timing of the TFI seam/crack tool on the Conway to Corsicana segment and that this omission resulted in the failure to identify threats and preventive and mitigative measures. In contrast, the record shows that no updated risk assessment was required under EMPCo IMP 5.4 or OIMS 2.4.

[18] In 2013, PHMSA cited EMPCo for a similar violation in a prior NOPV for which a Petition for Reconsideration is pending. *PHMSA Final Order, CPF No. 4-2011-5016 (June 27, 2013)*. As part of that action, PHMSA issued a Compliance Order with two items. Item 1 of the Compliance Order has been stayed pending a decision on the Petition, and EMPCo timely submitted revised procedures under Item 2 of the Compliance Order to the Southwest Region on August 1, 2013. PHMSA Inspector John Pepper responded to the proposed revisions requesting additional modifications on August 5, 2013; EMPCO addressed those in a further revised version submitted to PHMSA on August 29, 2013.

EMPCo OIMS Element 2.4 states that "risk assessments are updated at specified intervals and as changes occur" and EMPCo IMP Section 5.4 requires annual review of integrity conditions and when significant changes occur, an updated risk assessment. *Exhibit 5, EMPCo OIMS Framework Element 2.4; Exhibit 4, EMPCo IMP Manual Excerpt Section 5.4*. As discussed above, the March 2011 long seam failure susceptibility analysis determined that the Conway to Corsicana segment was not susceptible to seam failure and identified a conservative interval for seam reassessment by the summer of 2013. *Exhibit 29, EMPCo Conway to Corsicana LSFSA and Pipelife Analysis Excerpts (2011); Exhibit 35, EMPCo IMP IAD Form 1.2 Conway to Corsicana (3/15/2011).* Because this analysis did not change after March 2011 and no other integrity conditions changed, there was no requirement to revise the risk analysis. Further, a revised analysis would not have impacted the threat identification or any of the preventive or mitigative measures for this segment because the risk analysis did not rely upon the implementation of a seam/crack tool inspection in 2011 or 2012.

The allegations of Item 7 of the NOPV are without foundation because the requirement in EMPCo's procedures to perform an updated risk assessment did not apply in this instance. The fact that the Company recommended, scheduled, and employed a TFI seam/crack tool in advance of the conservative Pipelife reassessment interval demonstrates that EMPCo's IMP exceeded Part 195 integrity management rules. Moreover, it is illogical to assume that the anomaly at the ultimate point of rupture would have been reported by an earlier TFI seam/crack tool run. No anomaly was reported when EMPCo ran the tool in 2012-2013. Given that crack growth is associated with the passage of time, the anomaly at the point of rupture was even less likely to be detected at the earlier date when PHMSA alleges the tool should have been run.

NOPV Item 8: Alleged Failure to Follow O&M Procedure by Selective Use of Threat Identification and Risk Assessment Manual Process Results

In Item 8 of the NOPV, the Agency alleges that EMPCo failed to follow its Operations and Maintenance (O&M) procedures required under 49 C.F.R. Part 195.402 by selectively using its TIARA process in 2011, and that this led to a failure to properly characterize the result of a release to certain HCAs on the Conway to Foreman segment, including the Lake Maumelle Watershed. In actuality, the Agency appears to be asserting a violation of the IMP threat identification and analysis requirements set forth in 49 C.F.R. Part 195.452. The record clearly shows, however, that the Company's IMP, Operations Integrity Management System (OIMS), and TIARA procedures were consistent with applicable law. Further, EMPCo properly applied those processes which led to the identification of certain preventive and mitigative (P&M) measures to protect HCAs, including scheduling the installation of three emergency flow restriction devices (EFRDS) (two in the Lake Maumelle area) and running a TFI seam/crack tool. *Exhibit 36, EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11); Exhibit 37, EMPCO Conway to Corsicana EFRD Form 6.2 (7/21/11)*.

As discussed above, when performing its risk assessment analysis and continual evaluation, the Company properly followed the relevant Part 195 regulations and its own procedures which were drafted with input from key industry experts. *Exhibit 2, Muhlbauer Affidavit* ¶¶11-12 (stating that EMPCo "properly recognized the issues associated with LF-ERW pipe, reacted to the threats on the Pegasus pipeline, and complied with the Part 195 IMP regulations"). EMPCo identified HCA locations and types, including Lake Maumelle and other water bodies, and included them in the TIARA risk assessment dynamic segmentation and calculations. *Exhibit 7, EMPCo TIARA Manual Excerpts; Exhibit 28 EMPCO TIARA UDT Q&A Conway to Corsicana (2011)* (assessing a score of 57 for sensitive receptors above a 55 for high level of public concern). In addition, these sensitive areas and drinking water bodies were expressly considered in the Company's IMP P&M measures analysis. *Exhibit 36, EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11)* (considering whether drinking water bodies are potentially affected HCAs)*; Exhibit 37, EMPCO Conway to Corsicana EFRD Form 6.2 (7/21/11)*(considering the same).

In 2011, the TIARA process did not result in any identified threats and did not in turn trigger any requirement to re-characterize the risk of release to HCAs on the Conway to Corsicana segment. *Exhibit 34, EMPCo Conway to Corsicana Manufacturing Risk Assessment (2011)*; *Exhibit 36 Conway to Corsicana P&M Form 6.1 (7/21/11)*. Despite this fact, and the fact that a valve would not significantly reduce the modeled risk or consequence as defined by the regulatory criteria and TIARA modeling, EMPCo's IMP Data Integration Team recommended further review of proposed EFRD sites in the Lake Maumelle watershed area and the Cedar Creek Reservoir as risk reduction measures. *Exhibit 37, EMPCO Conway to Corsicana EFRD Form 6.2 (7/21/11).* This led to the decision to install three EFRDs in this area. As noted by risk management expert, Kent Muhlbauer, "risk reduction measures were chosen in proportion to perceived risks and in light of other potential incident scenarios, consistent with requirements and objectives of regulatory IMP." *Exhibit 2, Muhlbauer Affidavit* ¶ 12.

The allegations of Item 8 of the NOPV are without foundation because the Company complied with its own procedures and with applicable law. The fact that the Company identified the potential need for EFRDs in HCAs along the Conway to Corsicana segment shows EMPCo's diligence in going beyond minimal Part 195 requirements.

NOPV Item 9: Alleged Failure to Follow Procedure for Continual Evaluation and Assessment

In Item 9 of the NOPV, the Agency alleges that EMPCo failed to follow its Management of Change (MOC) procedure OIMS 7.2 when it merged testable segments in 2009. PHMSA contends that the longer testable segments negatively impacted the TIARA risk assessments by diluting risk scores on the Conway to Foreman segment. The record will show, however, that EMPCo complied with this its MOC procedure and that merging the segments could not have negatively impacted the risk assessment.

EMPCo's OIMS Management of Change process ensures that operational, procedural and physical changes are implemented in a systematic manner intended to ensure the integrity of EMPCo facilities. *Exhibit 5, EMPCo OIMS Framework Element 7.2***.** As discussed above, the Company completed MOC forms in 2005 that expressly considered the impact of the merger of testable segments on IMP risk assessments and concluded that there was no negative impact to the integrity risk assessment process. *Exhibit 10, EMPCo Management of Change Form No. 05-*

2829 (8/10/05); Exhibit 11, EMPCo Management of Change Form No. 05-2833 (8/10/05). Under the EMPCo TIARA dynamic risk segmentation, threats cannot be aggregated or masked over multiple miles. For that reason, the length of a testable segment does not impact the risk to any specific area of the pipeline. In short, the Company combined the testable segments in compliance with applicable law and this decision did not mask risk on the intermediate segments.

V. THE PROPOSED PENALTY IS NOT WARRANTED

A. Strict Liability is not Provided in the PSA, thus there is No Basis for the Alleged Violations or Proposed Administrative Penalties

As discussed in the preceding sections of this brief, the NOPV presumes that simply because an incident occurred, there have been violations of PHMSA's Part 195 regulations. That presumption would only apply if the PSA had a strict liability provision, but it does not. Although infrequent, it is possible for an incident to occur even when a pipeline operator has fully complied with applicable law. This is one such instance.

In the absence of regulatory violations, there is no basis for administrative penalties. EMPCo was in compliance with PHMSA's Part 195 regulations in regard to the Pegasus Pipeline. Thus, the alleged violations asserted in the NOPV are based on mistakes of fact and law and should be withdrawn entirely. In that event, no penalty is appropriate.

B. Even if it is Found that Violations did Occur, the Amount of the Penalty Proposed is Unwarranted

The Agency's proposed penalty of more than $2.6 million is not authorized by law. The penalty provisions of the PSA establish three limitations on the amount of civil penalties proposed in any PHMSA enforcement proceeding. First, Section 2 of the PSA establishes factors that the government must ("shall") consider in developing an appropriate proposed civil penalty for a pipeline incident. *49 U.S.C. § 60122(b)* (those factors appear again in PHMSA regulations at 49 C.F.R. Part 190.225). Second, any violation occurring prior to January 3, 2012, must be limited to a maximum penalty of $100,000 per day. *49 U.S.C. § 60122(a)(1).* Third, any "related series of violations" occurring prior to January 3, 2012, must be capped at no more than $1 million. *49 U.S.C. §60122(a)(1); 49 C.F.R. Part 190.223(a).*[19] Each of the nine Items in the NOPV is alleged to have commenced prior to January 3, 2012. Moreover, many of the allegations rely on the same purported evidence, thus the statutory cap of $1 million should apply.

[19] In reviewing the issue of civil penalty caps in the Pipeline Safety Act (PSA) during reauthorization efforts preceding the enactment of the Pipeline Safety Improvement Act of 2002, Senators Hollings and Kerry had the following exchange on the phrase "related series of violations": [Sen. Hollings]: "*I am seeking clarification that all information requests issued by the Secretary pursuant to a single incident investigation are considered "related" for purposes of calculating the $1,000,000 civil penalty cap for a 'related series of violations'…"* [Sen. Kerry]: *"It is the intention of this legislation to treat all information requests pursuant to a single incident investigation as 'related' for purposes of applying the civil penalty cap…" Senator Hollings (SC) and Senator Kerry (MA). "Pipeline Safety Improvement Act." Congressional Record 146:103 (Sept. 7, 2000), p. S8235.*

1. PHMSA's Statutory Penalty Authority

Until recently, PHMSA had not assessed administrative civil penalties in excess of the daily or "related series of violations" maximums, thus the manner in which PHMSA seeks to use its penalty authority is an issue of critical importance for both the Agency and the industry. The statutory language authorizing PHMSA penalty authority has not changed since it was enacted more than thirty years ago (other than to increase the maximum amounts available), and there is very little legislative history providing guidance on how the Agency should exercise its penalty authority. Similarly, the Agency has not issued any regulation or policy describing how it will apply its penalty authority, or how it intends to interpret the phrase "a related series of violations."

The only relevant guidance that the Agency has issued to date is its decision *In re: Colorado Interstate Gas Co., CPF 5-2008-1005 (Nov. 23, 2009) (CIG)*. In *CIG*, the Agency stated that it interpreted the phrase "related series of violations" to mean "a series of daily violations" of the same regulatory requirement. *Id. at p. 11.* To do otherwise, the *CIG* decision reasoned, "would effectively limit the number of violations that PHMSA could assess penalties on" in a given incident. *Id.* We disagree. Congress could have stated (and has, in other statutes[20]) that the penalty cap applied only to "multiple violations of a single requirement," but it did not use that language. Instead, it established a cap on "related series of violations." As noted in the Congressional Record, Senators Kerry and Hollings interpreted this phrase to mean "all violations related to a single incident,"[21] and that is the interpretation that it should be given in this proceeding. The statutory language is further supplemented by the *CIG* decision where the Agency held that Items in a NOPV may also be "related" (even if not daily violations of the same requirement) if the facts and law for the claims are "so closely related … that they are not separate and should be considered one violation." *CIG*, at 12.

2. The NOPV As Drafted Alleges a "Related Series of Violations"

Following the reasoning of the *CIG* decision (and the clear language of the statute), Items 1, 2, 3 and 4 of the NOPV in this case are clearly related. All four of those Items are inextricably intertwined, relying on the same facts and law. The essence of the Agency's claims for Items 1 through 4 of the NOPV is that EMPCo failed to properly conclude that the pipe segment at the point of rupture was susceptible to seam failure. As stated above in this brief, the Company believes that the IMP rules do not dictate a particular conclusion, but only a deliberative process. The Company undertook that process and documented it. Unfortunately, an incident occurred, despite the fact that the Company followed applicable law, and despite the fact that state of the art technology did not detect an actionable anomaly at the point of rupture prior to the incident.

But for the Agency's allegation that the Company failed to conclude that the pipe segment was susceptible to seam failure, there would be no basis for the purported violations asserted in Items 1 through 4. Item 1 specifically addresses the alleged failure to conclude that the pipe was susceptible to seam failure. Item 2 builds on that same allegation, by asserting that *because* the

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[20] *See e.g., Social Security Act*, 42 U.S.C. §1320(d)5(a)(3) (setting a maximum cap multiple violations of a single requirement).

[21] *See* f.n. 19.

Company did not conclude that the segment was susceptible to seam failure, it exceeded the length of time allowed to run a seam ILI tool (note that the Company ran other ILI tools during the five years in issue; it ***did*** run a seam tool only a few months after the five years in issue, even though not required by law; and the ILI seam tool was run before the incident occurred, reporting no actionable anomaly at the point of rupture). The Agency's PSVR cites the same evidence in support of both Items 1 and 2 (hydrostatic test data and IMP assessment worksheets). *PSVR, pp. 7, 13.*

Items 3 and 4 of the NOPV continue this reliance on a single allegation, using similar evidentiary support and referencing either directly or indirectly the same Part 195 regulations. Item 3 asserts that the Company failed to complete a Management of Change form for extending the five year reassessment interval invoked in Item 2. Again, but for the presumption that the rules require an operator to *conclude*, not just consider, that LF-ERW pipe is susceptible to seam failure, then there is no basis for a violation in Item 3 (or 1, or 2). The same holds true in regard to Item 4, which alleges – again – that because EMPCo failed to conclude the pipe was susceptible to seam failure, it did not properly prioritize the timing of the ILI seam tool runs on segments of the Pegasus pipeline.

There is only one alleged fact central to Items 1 through 4 of the NOPV, being that the Company failed to conclude seam failure susceptibility. Without that assertion, there is no basis for any violation of law in any of these four Items. For that reason, using both the plain language of the statute and the rationale articulated by the Agency in the *CIG* decision, Items 1 through 4 of the NOPV constitute "a related series of violations" that are "so closely related … that they are not separate and should be considered one violation." *CIG*, at 12.

Items 1 through 4 of the NOPV should be combined for proposed penalty purposes, with the combined penalty not to exceed $1 million.

3. The Proposed Penalty Fails to Consider and Appropriately Apply All Mitigating Factors

Even if the Agency (or the courts) concludes that Items in the NOPV are not a "related series of violations" in whole or in part, and thus not subject to the $1 million penalty cap, the combined proposed penalty does not take into account all factors associated with the incident, as required by the PSA and PHMSA regulations.[22] EMPCo requested and was provided a copy of PHMSA's PSVR for this matter, and although it does not specifically provide numeric penalty calculations (see discussion in Section 4 below), the PSVR does provide the Agency's mitigating factor analysis (*i.e.,* nature, circumstances, gravity, culpability, good faith, and other matters as justice may require) for each alleged violation. EMPCo does not intend to address each component of each violation, but it generally contests the mitigation analysis set forth in the PSVR. For instance, the report repeatedly alleges that the Company made conscious decisions not to comply with regulatory requirements that were clearly applicable,[23] and that it did not

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[22] 49 C.F.R. Part 190.225 states that "in determining the amount of a civil penalty…the [Agency] *shall* consider," among other things, the nature, circumstances and gravity of the alleged violation, as well as any good faith by the Respondent in attempting to achieve compliance. *49 C.F.R. Part 190.225* (emphasis added).

[23] PHMSA's own PSVR notes that EMPCo's response to the incident was timely, appropriate and in accordance with the Company's procedures. *PHMSA PSVR, CPF 4-2013-5027, pp. 11, 14.*

make reasonable interpretations of regulatory requirements. The record in this matter shows that the Company clearly complied with applicable regulatory requirements regarding IMP, and that it did not at any time make conscious decisions to disregard the law.

In addition, although the specific calculations of the proposed penalty have not been made available, the proposed penalty does not appear to consider the fact that EMPCo fully cooperated with all federal, State and local officials in good faith while responding to and investigating the causes of the incident. To date, the Company has spent more than $75 million in response to the Mayflower incident, and continues to review and revise its Integrity Management Program as a result of the incident. If for no other reason, the penalty proposed in this NOPV should be reduced in light of the cooperation and good faith shown by EMPCo in its efforts both during and after the incident, both of which are mitigating factors set forth in 49 C.F.R. Part 190.225.

4. Due Process Requires that an Agency's Penalty Rationale Be Articulated

Finally, the proposed penalty for this matter should be reduced for due process and policy reasons, because the NOPV as issued provided no explanation for the basis of the penalty, which on its face exceeds the statutory cap. PHMSA practice has evolved in recent years in terms of how the Agency interprets and applies its penalty authority. At present, the Agency does not provide any explanation in a NOPV of how a penalty was derived, or whether multi-day assessments are included.

Although many administrative agencies have published official penalty policies to explain how they intend to interpret and apply their statutory penalty authority, PHMSA has promulgated no such policy. Nor has it produced any guidance, interpretative letters or advisories for the regulated community and the public to refer to in anticipating how the Agency should or will exercise its penalty authority.

The Administrative Procedure Act (APA) requires that respondents be informed of "the matters of fact and law asserted" in any enforcement pleading, which should include a clear statement of the theory on which the agency will proceed with its case, such that the respondent understands the issues and is afforded full opportunity to present its defense at a hearing. *5 U.S.C. 554(b); Yellow Freight System v. Martin, 954 F.2d 353, 357 (6th Cir. 1992).*

PHMSA's failure to expressly allege multi-day or statutory maximum claims in its NOPV violates the due process requirements of the Constitution and the procedural requirements of the APA. As a matter of equity, policy and due process considerations, the Agency should reduce the proposed penalty in this matter. Penalty adjustment in this instance would benefit both the Agency and the regulated community by clarifying the application of the *CIG* decision.

VI. THE PROPOSED COMPLIANCE ORDER IS OVERBROAD

The Proposed Compliance Order (PCO) requests actions by the Company to review and improve management systems in regard to Items 1, 2, 5, 6 and 8 of the NOPV. There are nine separate substantive paragraphs in the PCO.[24] Paragraph 1 of the PCO is notably more expansive than the other elements of the PCO.

Paragraph 1 relates to Item 1 of the NOPV, and requests that the Company modify its IMP procedures concerning seam failure susceptibility analyses, seam integrity assessment plans and threat modeling. Item 1 of the PCO is intended to broadly address "all pre-70 ERW pipe *on any assets covered by the operator's IMP*." NOPV, p. 10 (emphasis added). None of the other requested actions in the PCO address "all assets" of the Company. Such an extension of requested relief regarding modification of IMP procedures relating to pre-70 ERW pipe outside of the Pegasus system goes beyond the specific facts and issues presented in the NOPV, and exceeds the scope of relief necessary to remedy the alleged harm in this case.

Established law holds that injunctive relief must be narrowly tailored to remedy the specific harm alleged, and that an overbroad scope of injunctive relief is an abuse of discretion. *Ahearn ex rel. N.L.R.B. v. Remington Lodging & Hospitality, 842 F. Supp. 2d 1186, 1205-1206 (D. Alaska 2012), appeal dismissed (Apr. 6, 2012), citing Park Vill. Apartment Tenants Ass'n v. Mortimer Howard Trust, 636 F.3d 1150, 1160 (9th Cir. 2011).* An administrative agency may not impose sanctions that are unwarranted in law or without justification in fact. *Am. Power & Light Co. v. Sec. & Exch. Comm'n, 329 U.S. 90, 112-13 (1946); Syverson v. U.S. Dep't of Agric., 601 F.3d 793, 800 (8th Cir. 2010).* Accordingly, the PCO requirements constitute an abuse of agency discretion and are potentially subject to judicial review under the APA.

As made evident in this brief, EMPCo recognizes that the IMP rules intend that both industry and the Agency learn from incidents as part of the process of continual evaluation, regardless of whether violations of the rules occurred. The Company has already begun a review of its IMP program and procedures in light of the Pegasus incident, and it intends to continue that review and revision even before a Final Order issues in this case (at which time any proposed Compliance Order would take effect). The ongoing review that is being undertaken by the Company is expected to fully address the terms of the PCO (including Paragraph 1), but the Company respectfully reserves its objections as stated.

VII. SUMMARY AND RELIEF REQUESTED

It is clear that PHMSA issued this NOPV solely because a high profile incident occurred. EMPCo does not minimize the significance of the incident; the Company has assumed responsibility for it, and continues to work with numerous parties to resolve all issues resulting from the event. The Company does challenge the Agency's enforcement response, however. The Agency inspected the Company's IMP program several times prior to the incident, and found no violations related to the allegations in this NOPV. But once the incident occurred, the Agency presumed that there must have been violations of the Part 195 regulations, and the IMP rule specifically. That approach, and presumption, is not authorized by the PSA.

[24] Paragraph 1 relates to Item 1 of the NOPV; Paragraph 2 relates to Item 2; Paragraphs 3, 4 and 5 of the PCO relate to Items 5 and 6 of the NOPV; Paragraphs 6 and 7 of the PCO relate to Item 8 of the NOPV; Paragraph 8 relates to Items 3 through 7 of the NOPV, regarding documentation; and Paragraph 9 of the PCO is a non-mandatory request for retention of cost records.

No Strict Liability under the PSA

There is no strict liability provision in the Pipeline Safety Act to establish liability without fault or causation. The Agency must prove that violations occurred, not simply that an accident occurred. Although the Agency may be reluctant to acknowledge this, accidents can occur even when an operator is in full compliance with the rules. This is one such accident. Even though the Company was in compliance with the IMP rules in this instance, and no actionable anomaly was reported by state of the art inspection tools at the point of rupture, the accident nonetheless occurred.

EMPCo Complied with Applicable IMP Regulations

The core of the Agency's allegations in the NOPV is that EMPCo failed to *conclude* that the pipe segment in issue was susceptible to seam failure. Hindsight is indeed perfect, but the IMP regulations only require that an operator *consider* the risk of seam failure on LF-ERW pipe, not automatically conclude it. EMPCo did carefully consider the risk of seam failure on this segment. The Company reviewed the issue multiple times over several years, and documented its compliance with the rules on every occasion.

If the Agency's core allegation regarding seam failure susceptibility is incorrect, then Items 1 through 4 of the NOPV, at a minimum, fail to state a claim. If the Agency's core allegation is upheld, however, then the entire industry and the public must now reconsider the Agency's rules and precedent regarding LF-ERW pipe. Nearly one quarter of all oil pipelines in the U.S. contain LF-ERW pipe. If operators must now conclude that such pipe is automatically susceptible to seam failure – without allowing for the evaluation and consideration process set forth in the rules and used by all parties up to now – then the time and cost to implement that conclusion could affect energy supplies throughout the U.S. Moreover, such a sweeping characterization would undermine the public's faith in PHMSA's ability to monitor pipeline integrity and safety in a logical and consistent, rather than a purely reactive manner.

As with most activities, it is not possible to predict and prevent all accidents. The Pipeline Safety Act, and PHMSA regulations, establish a framework that requires careful identification of threats, analysis of those threats, inspection methods designed to find problems before they become manifest, and strategies to reduce and mitigate risks. That system has worked, as made evident by the continually declining number and size of pipeline incidents over the past twenty years.

Despite the success of the Agency's pipeline integrity management program, some accidents can occur even when an operator is in full compliance with the rules. In this instance, the Company not only complied with the IMP rules, it did more than what was minimally required. Nationally recognized experts (relied upon by PHMSA even in this proceeding) consulted with EMPCo on its compliance with IMP rules before this incident occurred and their affidavits in this matter lend strong support to the Company's arguments. Even though the pipe was not deemed susceptible to seam failure, the Company voluntarily ran the same tools and took the same risk reduction methods beyond those required under the regulations. Significantly, an ILI seam tool did not report any actionable anomaly at the point of rupture before the incident occurred. That fact alone undercuts all of the government's assertions in the NOPV.

Neither a Penalty nor the PCO is Warranted

If the basic premise of the NOPV is wrong, then there is obviously no basis to assess any administrative penalties against the Company. Even if the Agency's alleged violations are upheld, the penalty should be adjusted downward. Items 1 through 4 of the NOPV are so closely related as to constitute a single violation, subject to a $1 million penalty cap. The other alleged violations also depend on erroneous presumptions, not supported by the record. Instead of applying mitigation factors in light of the Company's cooperation, the NOPV erroneously asserts that the Company made a conscious decision not to comply with the law, even while the Company did more than the minimum required.

Similarly, if the substantive allegations of the NOPV are unfounded, then there is no basis for a Proposed Compliance Order (PCO). The Company objects to the scope of the PCO, which purports to apply to "all assets" of the Company, rather than just the pipeline at issue. That is unusual, and unlawful. The Company contests that overly broad aspect of the PCO, but the Company is also already pursuing the elements of the PCO, as it is EMPCo's understanding that the IMP rules properly read require continual evaluation and improvement, regardless of any PCO. The public and the industry would be well served if the Agency used its resources to learn from this incident, rather than to deflect concerns about application of rules, guidance and available technology.

For all of these reasons, EMPCo respectfully requests that the NOPV be withdrawn, or significantly revised in accord with applicable law and precedent.

Respectfully submitted,

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Date: June 2, 2014

Index of Attached Exhibits

No.	Exhibit
1	Affidavit of John Kiefner (5/22/14)
2	Affidavit of Kent Muhlbauer (5/31/14)
3	M. Baker, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Chapter 4 & Figure 4.1 (April 2004)
4	EMPCo IMP Manual Excerpts, Sections 4.4, 5.1(4), 5.4 (2012)
5	EMPCo OIMS Framework, Elements 2.4; 7.2 (2009)
6	EMPCo OIMS System 2A, Attachment #1 Risk Matrix Methodology (rev'd 2004)
7	EMPCo TIARA Manual, Section 8.0 (2007)
8	EMPCo Memo regarding Corsicana to Patoka LSFSA (12/10/04)
9	EMPCo Memo regarding Corsicana to Patoka LSFSA (2/10/05)
10	EMPCo Management of Change Form No. 05-2829 (8/10/05)
11	EMPCo Management of Change Form No. 05-2833 (8/10/05)
12	EMPCo Hurst Metallurgical Analysis of Hydrotest Failures Excerpt Report No. 51708 (6/21/06)
13	EMPCo TIARA Foreman to Conway UDT Q&A (6/26/06)
14	EMPCo Corsicana to Patoka Summary of Hydrotest Learnings (7/06/06)
15	EMPCo Hurst Metallurgical Analysis of Hydrotest Failures Excerpt Report No. 51763 (7/06/06)
16	EMPCo IMP Integrity Assessment Data (IAD) Form 3.2 Foreman to Conway (7/26/06)
17	EMPCo TIARA Foreman to Conway Manufacturing Threat Classification (7/26/06)
18	EMPCo TIARA Foreman to Conway Risk Assessment Summary (7/27/06)
19	EMPCo Risk Assessment Summaries: Corsicana to Foreman, Conway to Doniphan, Doniphan to Patoka (2006/2007)
20	EMPCo IMP Preventive & Mitigative Actions (P&M) Form 6.1, Foreman to Conway (2007)
21	EMPCo Foreman to Conway LSFSA and Pipelife Analysis Excerpts (2007)
22	EMPCo Patoka to Corsicana LFSA Review (2009)
23	EMPCo Email from NDT (8/23/10)

No.	Exhibit
24	EMPCo NDT Preliminary ILI Report Conway to Corsicana (received 8/23/10)
25	EMPCo Repair Form PL-0751 MP 164.05 (8/28/10)
26	EMPCo IMP Exception Form 1.2 (12/17/10)
27	EMPCo Final NDT ILI Report & Repair Summary Conway to Corsicana Excerpts (2011)
28	EMPCo TIARA UDT Q&A Conway to Corsicana (2011)
29	EMPCo Conway to Corsicana LSFSA and Pipelife Excerpts (2011)
30	EMPCo Email from NDT & MP 142.39 Dig Sheet (1/10/11)
31	EMPCo Repair Form PL-0751 MP 142.39 (1/12/11)
32	EMPCo Repair Form PL-0751 MP 274.09 (1/13/11)
33	EMPCo IMP Exception Form 1.2 (1/31/11)
34	EMPCo Conway to Corsicana Manufacturing Threat Classification (3/4/11)
35	EMPCo Conway to Coriscana IMP Form 3.2 IAD Form (3/15/11)
36	EMPCo Conway to Corsicana P&M Form 6.1 (7/21/11)
37	EMPCo Conway to Corsicana EFRD Form 6.2 (7/21/11)
38	EMPCo IMP Exception Form 1.2 (8/02/13)
39	EMPCo IMP Exception Form 1.2 (8/28/13)

Index of Exhibits Included by Reference Only

No.	Exhibit
40	EMPCo Patoka to Corsicana 2005/2006 Hydrostatic Test Reports (MP 127-437)
41	EMPCo Metallurgical Analysis performed by Hurst Report No. 40912-F (12/19/05)
42	EMPCo LSFSA Foreman to Conway and Pipelife Analysis (2006)
43	EMPCo Metallurgical Analysis performed by Hurst Report No. 41305 (4/20/06)
44	EMPCo Metallurgical Analysis performed by Hurst, Report No. 41500 (4/24/06)
45	EMPCo Metallurgical Analysis performed by Hurst Report No. 51695 (6/17/06)
46	EMPCo Metallurgical Analysis performed by Hurst Report No. 51708 (6/21/06)
47	EMPCo Metallurgical Analysis performed by Hurst Report No. 51763 (7/6/06)
48	EMPCo TIARA Foreman to Conway Risk Assessment (7/27/06)
49	EMPCo TIARA Manual (2007)
50	EMPCo Conway to Corsicana NDT MFL Combo ILI Final Report (2010)
51	EMPCo Patoka to Conway GE PII TFI Final Report (2010)
52	EMPCo LSFSA Conway to Corsicana and Pipelife Analysis (2011)
53	EMPCO IMP Manual (2012)
54	EMPCo Conway to Corsicana GE PII TFI Final Report (2013)
55	Hurst Metallurgical Investigation of Pegasus Pipeline Report No. 64961 MP 314 (7/9/13)
56	EMPCo Pegasus Root Cause Failure Analysis Final Report & Appendices (3/26,/14)