U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Ave, S.E.
Washington, D.C. 20590

DEC 02 2009

Mr. Terry Hurlburt
Senior Vice President of Operations
Enterprise Products Operating, LLC
1100 Louisiana Street
Houston, TX 77002

Re: CPF No. 4-2007-5015

Dear Mr. Hurlburt:

Enclosed is the Final Order issued in the above-referenced case. It makes findings of violation, assesses a civil penalty of $31,000, and specifies actions to be taken to comply with the pipeline safety regulations. The penalty payment terms are set forth in the Final Order. When the civil penalty has been paid and the terms of the compliance order completed, as determined by the Director, Southwest Region, this enforcement action will be closed. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. R. M. Seeley, Director, Southwest Region

VIA CERTIFIED MAIL – RETURN RECEIPT REQUESTED [7005 0390 0005 6162 5098]

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
	)	
Enterprise Products Operating, LLC,	)	**CPF No. 4-2007-5015**
	)	
Respondent.	)	

FINAL ORDER

On February 21–25, April 5–8, 18–22, and May 2–6, 16–20, 2005, pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration's Office of Pipeline Safety (PHMSA) conducted an on-site pipeline safety inspection of the hazardous liquid pipeline facilities operated by Enterprise Products Operating, LLC (Enterprise or Respondent) in New Mexico, Texas, and Oklahoma. Enterprise operates over 20,000 miles of hazardous liquid and natural gas pipeline facilities in those and other states, as well as offshore in the Gulf of Mexico. The facilities and records of the following systems were inspected: Four Corners, Hobbs East, Hobbs West, Skellytown, and the Cameron Highway Oil Pipeline.

As a result of the inspection, the Director, Southwest Region (Director), issued to Respondent, by letter dated May 7, 2007, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had committed violations of 49 C.F.R. Part 195, proposed assessing a civil penalty of $31,000 for the alleged violations, and proposed ordering Respondent to take certain measures to correct them. In accordance with 49 C.F.R. § 190.205, the Notice also proposed finding that Respondent had committed certain probable violations of 49 C.F.R. Part 195 and warned Respondent to take appropriate corrective action to address them or be subject to future enforcement action.

Respondent responded to the Notice by letter dated June 8, 2007 (Response). Respondent contested the allegations and requested that the Notice be withdrawn. Respondent did not request a hearing, and therefore has waived its right to one.

FINDINGS OF VIOLATION

The Notice alleged that Respondent violated 49 C.F.R. Part 195, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.406, which states:

> **§ 195.406 Maximum operating pressure.**
> (a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following . . . .
> (b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

The Notice alleged that Respondent violated § 195.406(b) by failing to provide adequate controls and protective equipment to control pressure within 110 percent of the established maximum operating pressure (MOP) during surges and other variations from normal operations. Specifically, the Notice alleged that Enterprise had not considered the potential for surge pressure on all of its pipelines, and therefore could not demonstrate its pipelines had adequate protective equipment to control pressure within 110 percent of MOP during surges.

In its Response, Enterprise contended that § 195.406(b) does not require consideration of pressure surges. Respondent also claimed that surges are not an issue for the inspected pipelines, which have never had any incidents of overpressure caused by surges. Based on its operating experience, Respondent contended that its controls and protective equipment were adequate.

Section 195.406 requires that operators establish a safe MOP for normal operations, and further provides that in order to protect a pipeline during momentary pressure excursions caused by surges, operators must have adequate controls and protective equipment to control pressure during surges to within 110 percent of the established MOP. While I agree with Respondent that the text of the regulation does not explicitly state an operator shall "consider" the potential for surges, I disagree with the company's contention that consideration of surges is not a requirement of the regulation. In order for an operator to understand if its controls and protective equipment are "adequate" to protect a pipeline from spikes in pressure caused by surges, it is necessary for the operator to consider the potential for such surges and to understand and account for their potential effects when designing appropriate controls and protective equipment. If an operator has not at least considered the potential for surges on its pipeline, there cannot be an informed judgment about the adequacy of the operator's controls to prevent pressure from exceeding 110 percent of MOP during surges.

The evidence shows that during the inspection of Respondent's facilities, the PHMSA representative requested documentation to verify that Enterprise's controls and protective equipment were adequate to control pressure. His request included records to show that Respondent had analyzed the potential for surges on its pipelines. Respondent was able to produce surge analyses for several but not all of the inspected pipelines. In its Response, Respondent did not produce any additional surge analyses but contended that surge pressures were simply not an issue for its pipelines.

Respondent's claim that surge pressures are not an issue is unsubstantiated by the evidence in the record. Furthermore, even if a particular pipeline has no known incident of overpressure in the past, that does not guarantee the pipeline will never experience an overpressure caused by a surge in the future. Simply noting that a pipeline has not experienced a surge in the past does not demonstrate that controls and protective equipment are adequate to control pressure within 110 percent of MOP in the event a surge or other variation from normal operations were to occur.

After considering all the evidence, I find that Respondent violated 49 C.F.R. § 195.406(b) by failing to provide controls and protective equipment demonstrated to be adequate to control pressure within 110 percent of MOP during surges and other variations from normal operations.

Item 4: The Notice alleged that Respondent violated 49 C.F.R. § 195.432, which states:

> **§ 195.432 Inspection of in-service breakout tanks.**
> (a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.
> (b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under § 195.402(c)(3).
> (c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.
> (d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.

The Notice alleged that Respondent violated § 195.432(b) and (c) by failing to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653, and by failing to inspect steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.[1] The Notice further alleged that Enterprise did not have a written inspection program for breakout tanks.[2] The PHMSA representative noted during the inspection that Enterprise employees were not aware of the need to determine inspection intervals in accordance with API 653 and API 510 and that the company had been performing annual inspections pursuant to an outdated requirement in § 195.432.[3]

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[1] American Petroleum Institute (API) Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," and API Standard 510, "Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration," are both incorporated by reference at 49 C.F.R. § 195.3.

[2] *See also* 49 C.F.R. § 195.402(c)(3), "Procedural manual for operations, maintenance, and emergencies," which specifies that operators must prepare and follow written procedures for conducting operations and maintenance activities in accordance with § 195.432, among other requirements.

[3] PHMSA amended § 195.432 in 1999 by incorporating the API consensus standards in order to improve the level of safety applicable to maintenance inspections of breakout tanks. Before the revision, § 195.432 only generally required that all breakout tanks be inspected annually. *See* Pipeline Safety: Adoption of Consensus Standards for Breakout Tanks, 64 Fed. Reg. 15,926 (Apr. 2, 1999).

In its Response, Enterprise contested the allegation of violation and contended that the subject breakout tanks had been inspected in full compliance with both API 653 and API 510. Respondent submitted records from two breakout tank examinations that occurred on April 20, 2004 (tank numbers VSP-2010 and VSP-2020). Respondent also submitted an inspection schedule that demonstrated the next visual inspections for the two tanks, among others, were to be performed in 2009 and the next ultrasonic inspections were to be performed in 2014.

Section 195.432(b) and (c) requires operators to perform maintenance inspections of breakout tanks at periodic intervals established in accordance with API 653 and API 510. In particular, API 653 provides that periodic inspection intervals for atmospheric and low-pressure breakout tanks shall be determined on the basis of specific factors listed therein; further, API 510 provides that inspection intervals for breakout tanks built to API 2510 shall be based on a calculated corrosion rate. Section 195.402(c)(3) also requires that operators have written procedures for performing inspections of breakout tanks in accordance with § 195.432, including the establishment of inspection intervals.

While Respondent claimed in its Response that it had performed inspections consistent with all of these requirements, the operator failed to submit evidence that demonstrated full compliance. Neither the inspection records for the two tanks nor the inspection schedule show that Enterprise had performed inspections at intervals determined in accordance with API 653 and API 510. Furthermore, the evidence does not include any written procedures demonstrating that Respondent had prepared (and followed) a program for conducting breakout tank inspections, including the establishment of inspection intervals based on the consideration of the specific factors listed in those standards.

Accordingly, after considering all the evidence, I find that Respondent violated 49 C.F.R. § 195.432(b) and (c) by failing to inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653, and steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510.

Item 5: The Notice alleged that Respondent violated 49 C.F.R. § 195.573, which states:

> **§ 195.573 What must I do to monitor external corrosion control?**
>
> (a) *Protected pipelines.* You must do the following to determine whether cathodic protection required by this subpart complies with §195.571:
>
> (1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months . . . .
>
> (d) *Breakout tanks.* You must inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under

> §195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

The Notice alleged that Respondent violated § 195.573(a) and (d) by failing to conduct tests on protected pipelines to determine whether cathodic protection complied with § 195.571, and by failing to inspect cathodic protection used to control corrosion on the bottom of aboveground breakout tanks to ensure that it complied with API Recommended Practice (RP) 651.[4] Specifically, the Notice alleged that Enterprise had not considered voltage (IR) drop when surveying cathodic protection systems, did not have dedicated cathodic protection systems for breakout tank bottoms, and failed to survey tank bottoms during annual cathodic protection surveys. The Notice further alleged that Respondent's first-ever interrupted survey (to account for IR drop) was conducted during the 2005 PHMSA inspection.

During that inspection, the PHMSA representative noted that Enterprise's survey methods did not account for the revised safety standards established in 2002 by the promulgation of §§ 195.571 and 195.573.[5] Until then, operators were required only to test cathodic protection systems to determine whether the protection was "adequate."[6] Effective January 28, 2002, § 195.571 established paragraphs 6.2 and 6.3 of NACE Standard RP 0169 as the standard for determining the adequacy of cathodic protection systems for pipelines.[7] Section 195.573(a) further requires that operators conduct tests on protected pipelines to determine if cathodic protection complies with those standards. Likewise, § 195.573(d) establishes API RP 651 as the standard for determining the adequacy of cathodic protection systems for breakout tanks. Both paragraphs 6.2.2.1.1 of NACE RP0169 and 8.2.2.1 of API RP 651 state that an operator may use the -850 mV criterion for determining the adequacy of cathodic protection, but both standards provide that "[v]oltage drops other than those across the structure [or tank bottom]-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement."

Protected Pipelines

In its Response, Enterprise contested the allegations of violation and contended that the company has always considered IR drop for its pipelines. Respondent explained that it considered IR drop in a variety of ways, including: measurement of IR drop via interrupted annual or close-interval cathodic protection surveys; use of "IR-free" coupon test stations; visual observation and measurement of pipe-wall thickness when lines are exposed; use of internal inspection devices; corrosion leak history analysis; at-grade versus in-the-ditch pipe-to-soil potential measurements at pipeline excavation sites; and potential measurement techniques that consider proper reference cell placement and pipeline location.

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[4] API Recommended Practice 651, "Cathodic Protection of Aboveground Petroleum Storage Tanks," is incorporated by reference at 49 C.F.R. § 195.3.

[5] *See* Controlling Corrosion on Hazardous Liquid and Carbon Dioxide Pipelines, 66 Fed. Reg. 66,994 (Dec. 27, 2001).

[6] *See* 49 C.F.R. § 195.416 (2001).

[7] NACE International (NACE) Standard RP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," is incorporated by reference at 49 C.F.R. § 195.3.

With respect to the interrupted annual or close-interval surveys, Respondent stated that in 2003, the company conducted 396 miles of "interrupted/IR-free" annual or close-interval cathodic protection surveys across all of its pipeline systems. Respondent also indicated that in 2004, it conducted 65 miles of interrupted close-interval cathodic protection surveys and developed a plan to accomplish several goals within five years, such as: conducting 20 percent of its annual cathodic protection surveys for all of its pipeline systems using interrupted/IR-free surveys; performing all close-intervals in an interrupted/IR-free manner; and installing IR-free coupon test stations. Respondent indicated that pursuant to this five-year plan, it had completed more than 7,000 miles of interrupted/IR-free annual or close-interval surveys and installed 263 IR-free coupon test stations throughout its pipeline system.

Enterprise further indicated that it had conducted 396 miles of surveys across all of its pipeline systems in 2003, but did not indicate what portion of the 3,200 miles of pipelines subject to this enforcement action were included in that total. Regardless, I note that Respondent did not claim that it performed interrupted or close interval surveys on *all* 3,200 miles of its pipelines in 2003. From 2004 through 2007, Respondent indicated it conducted 7,000 miles of interrupted or close-interval surveys on all of its pipelines; but for 2004 the company has only accounted for 65 miles of the pipelines subject to this enforcement action, and did not specifically account for any of the subject pipelines for individual survey years 2005, 2006, or 2007.

With respect to the various other methods that Enterprise claimed to have used to consider IR drop, the evidence in the record does not reflect the actual use of them all. Respondent's annual cathodic protection survey records do not show they were all used, nor did Respondent submit any other documentation, such as reports or summaries, that document the use of all these methods in a manner that would enable Respondent to determine whether its cathodic protection systems complied with applicable standards. Without such supporting evidence, I am unable to find the use of all of these various methods actually met the specifications of § 195.573.

Breakout tanks

The Notice further alleged that Respondent did not have dedicated cathodic protection systems for breakout tank bottoms. In its Response, Enterprise contended that such allegation, even if true, did not state a violation of any PHMSA regulation because neither the code nor industry standards required dedicated cathodic protection for tank bottoms. Respondent explained that the cathodic protection system protecting the breakout tank at Skellytown Station is a deepwell/impressed-current system that also protects below-grade station piping.

After reviewing the relevant safety requirements, I do not find any apparent requirement in § 195.573(d) that an operator must have a *dedicated* cathodic protection system for its breakout tank bottoms. Accordingly, I am withdrawing the allegation that Respondent's failure to provide a dedicated cathodic protection system for breakout tank bottoms constituted a violation of § 195.573(d).

In addition, the Notice alleged that Respondent failed to survey tank bottoms in accordance with § 195.432(d) during annual cathodic protection surveys. In its Response, Enterprise contended that cathodic protection potentials were measured at the four compass bearing locations (North, South, East and West) around the perimeter of the subject breakout tank and were recorded during annual cathodic protection surveys of the station. Respondent submitted records of those surveys.

The records show that Respondent inspected the cathodic protection system used to control corrosion on the bottom of the breakout tank at Skellytown Station during calendar years 2003, 2004, and 2005; however, the records do not demonstrate that these cathodic protection surveys considered IR drop for valid interpretation of the -850 mV criterion in accordance with § 195.432(d) and API RP 651.

Accordingly, after considering all the evidence, I find Respondent violated 49 C.F.R. § 195.573(a) and (d) by failing to conduct tests on protected pipelines to determine whether cathodic protection complies with § 195.571, and by failing to inspect each cathodic protection system used to control corrosion on the bottom of aboveground breakout tanks to ensure that the systems comply with API RP 651.

Item 6: The Notice alleged that Respondent violated 49 C.F.R. § 195.579, which states:

> **§ 195.579 What must I do to mitigate internal corrosion?**
> (a) *General.* If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion . . . .
> (c) *Removing pipe.* Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under §195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe . . . .

The Notice alleged that Respondent violated § 195.579(a) and (c) by failing to investigate the corrosive effect of the hazardous liquid transported by pipeline. Specifically, the Notice alleged Respondent failed to sufficiently investigate and monitor for internal corrosion and to perform inspections to determine whether internal corrosion could develop in its pipeline system. The Notice further alleged that Respondent used coupons to check for internal corrosion but did not properly locate the coupons so they would accurately detect the corrosion. It also alleged Respondent did not inspect pipe that had been removed from service for evidence of internal corrosion.

In its Response, Enterprise contended that it did investigate, detect, prevent, and mitigate internal corrosion through its integrity management (IM) program and its operations and maintenance (O&M) program. Through its IM program, Respondent stated it conducted inline inspections (ILI) using a smart pig to identify various pipe-wall anomalies such as internal corrosion, and it investigated anomalies that met remediation criteria. In addition, through its O&M program, Respondent stated it used internal coupons throughout its pipeline system to yield data on internal corrosion. The validity of the coupons data was demonstrated, according to Respondent, by the fact that the data corresponded with results from the IM anomaly investigations. Finally, Respondent indicated it inspected pipe removed from service for internal corrosion, as evidenced by a sample report submitted for the record.

By regulation, Respondent is required to implement its IM program for each pipeline segment that could affect a "high consequence area" (HCA).[8] According to Respondent's annual report, less than one-fifth of Respondent's hazardous liquid pipeline system could affect an HCA. Since Respondent's IM program is required to cover only a fraction of the pipelines, the use of ILI pursuant to Respondent's IM program would be inadequate to monitor for corrosive effects on the entire system. In addition, inline inspections of mainline pipe are not representative of the entire pipeline system because internal corrosion generally occurs first in dead- and intermittent-flow areas that cannot typically accommodate passage of an ILI device. For this reason, an inline inspection of mainline pipe may show few, if any, issues with internal corrosion even where there is significant internal corrosion in non-piggable portions of the system.

The Notice also alleged the coupons used by Respondent to monitor for internal corrosion were improperly located. While Respondent indicated in its Response that the location of its approximately 30 coupons did not affect the reliability of the data, it was noted during PHMSA's inspection that the coupons were located at the top of the pipelines. Normally, top-of-line locations give little or no indication of corrosion because internal corrosion generally occurs first on the bottom of the pipe. In its Response, Enterprise acknowledged that many of its coupons were located on the top of the pipe and that the preferred location is on the bottom. Respondent also indicated the company is in the process of relocating its monitoring coupons to the bottom of the pipe.

Finally, Respondent submitted documentation as evidence that it investigates internal corrosion when pipe is removed from the pipeline. The evidence Respondent provided is an accident investigation report, which documented a third-party investigation of a pipeline failure on Enterprise's system. The report stated, in part, "The pipe segment that was examined on receipt showed no external or internal corrosion . . . ." While the statement indicates the internal surface of the pipe removed was inspected in this instance, this single documented occurrence does not demonstrate Respondent routinely inspected pipe that was removed from its pipeline system. For example, Respondent provided no written procedures, forms, or other records that demonstrated it was Respondent's regular practice to investigate internal corrosion when sections of pipe were removed from the pipeline.

For the reasons stated above, I find Respondent's use of ILI pursuant to its IM program was not an acceptable method of investigating and monitoring internal corrosion across its entire system and that the use of coupons on the top of the pipeline also was not a sufficient means of investigating internal corrosion. I further find Respondent failed to submit sufficient evidence to support its claim that it routinely inspected the internal surface of pipe removed from a pipeline.

Accordingly, after considering all the evidence, I find that Respondent violated 49 C.F.R. § 195.579(a) and (c) by failing to investigate the corrosive effect of the hazardous liquid on the pipeline, and by failing to inspect the internal surface of the pipe for evidence of corrosion whenever pipe has removed from a pipeline.

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[8] 49 C.F.R. § 195.452.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

WITHDRAWAL OF ALLEGATION

Item 2 in the Notice alleged that Respondent violated 49 C.F.R. § 195.410, which states:

> **§ 195.410 Line markers.**
> (a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:
> (1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known . . . .

The Notice alleged that Respondent failed to place a sufficient number of line markers over each buried pipeline in agricultural fields, so that the location of the pipeline would be accurately known. Specifically, the Notice alleged that some markers on the far side of agricultural fields could not be seen and that, when looking in both directions from some valve sites, the next line marker could not be seen.

In its Response, Enterprise asserted that it had sufficient line markers in agricultural fields to adequately mark its pipeline. Respondent also indicated that in July 2005, the company filed a request for a "waiver" (now called a special permit) seeking PHMSA's permission to employ alternate means of compliance with § 195.410(a)(1) in agricultural fields.

PHMSA has not yet acted upon Respondent's 2005 special permit request but acknowledges that applying a so-called "line-of-sight" test, has resulted in confusion within the industry and differing application among the regions. As a result of this uncertainty, the agency has initiated a re-examination of the use of a "line-of-sight" test but no decision has yet been made on whether or how it should be applied.[9] Under such circumstances, I find that it is appropriate to withdraw this allegation of violation. Such withdrawal neither constitutes an interpretation of § 195.410(a)(1) nor prejudices future potential enforcement action against Respondent or any other operator.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed $100,000 per violation for each day of the violation, up to a maximum of $1,000,000 for any related series of violations. The Notice proposed a total civil penalty of $31,000 for the violation of § 195.406(b) **(Item 1)**.

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[9] PHMSA held a public workshop on February 20-21, 2008 in Houston, Texas, to discuss, among other issues, the location of the markers. *Pipeline Safety: Workshop on Public Awareness Programs for Pipeline Operators and Location of Line Markers,* 73 Fed. Reg 223 (Jan.2, 2008).

In determining the amount of a civil penalty under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, I must consider the following criteria: the nature, circumstances, and gravity of the violation, including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; the Respondent's ability to pay the penalty and any effect the penalty may have on its ability to continue doing business; and the good faith of Respondent in attempting to comply with the pipeline safety regulations. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require.

Respondent violated § 195.406(b) by failing to provide controls and protective equipment demonstrated to be adequate to control pressure within 110 percent of MOP during surges and other variations from normal operations. Surges and other variations from normal operations can cause pressure in a pipeline to exceed the safe operating pressure, and may even lead to a pipeline rupture and release of hazardous liquid, presenting a danger to the public and environment. To protect against the risks of overpressure caused by surges, § 195.406(b) requires pipeline operators to have adequate controls to prevent pressure from exceeding 110 percent of MOP. Enterprise failed to consider the potential for surge pressures on all of its pipelines, and therefore could not demonstrate that the company had adequate protective equipment to control pressure within 110 percent of MOP during surges. I find the nature, circumstances, and gravity of the violation support assessment of the proposed civil penalty.

Respondent is fully culpable for the violation, meaning the company operates the subject pipelines and therefore is liable for violations of the governing safety regulations at 49 C.F.R. Part 195. With regard to the history of prior offenses, there is evidence in the record that Respondent has been the subject of several previous enforcement actions involving the assessment of civil penalties for violations of the pipeline safety regulations. Respondent did not provide any evidence suggesting the company is not able to pay the proposed civil penalty. Therefore, I find Respondent is able to pay the proposed penalty without adversely affecting its ability to continue in business. I have also considered Respondent's good faith in attempting to comply with the pipeline safety regulations but find it is insufficient to warrant a reduction in the proposed civil penalty.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $31,000.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-341), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-8893.

Failure to pay the $31,000 civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9, and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Items 1, 4, 5 and 6 in the Notice for violations of §§ 195.406, 195.432, 195.573, and 195.579, respectively.

Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids by pipeline or who owns or operates a hazardous liquid pipeline facility is required to comply with the applicable safety standards established under chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Enterprise is ordered to take the actions listed below with respect to the following pipeline facilities to ensure compliance with the pipeline safety regulations: Hobbs Area West; Hobbs Area East; Skellytown Unit; Four Corners Unit; Ammonia Unit; and CHOPS Unit. Respondent must—

1. Perform and submit within 30 days of receipt of this Final Order an audit determining if the pipelines have controls and protective equipment required by § 195.406(b) to prevent pressure from exceeding 110 percent of maximum operating pressure during surges and other variations from normal operations. The audit must include consideration of the potential for surges, in addition to a plan and timeline for completing installation of controls and protective equipment, as necessary, within 365 days following the receipt of the Final Order, to ensure compliance with § 195.406(b).

2. Perform and submit within 30 days of receipt of this Final Order an audit evaluating Enterprise's inspection of the physical integrity of in-service steel aboveground breakout tanks in accordance with § 195.432. Based upon that audit, develop and submit a program within 60 days of receipt of this Final Order for inspecting the physical integrity of in-service steel breakout tanks in accordance with § 195.432(b) and (c) and the applicable standards incorporated by reference (section 4 of API Standard 653 and section 6 of API 510).

3. Perform and submit within 30 days of receipt of this Final Order an audit evaluating Enterprise's testing of cathodic protection systems protecting pipelines and the bottom of aboveground breakout tanks in accordance with § 195.573. Based upon that audit, develop and submit a plan within 60 days of receipt of this Final Order for conducting cathodic protection surveys in accordance with § 195.573(a) and (d) to ensure the facilities have adequate cathodic protection.

4. Perform and submit within 30 days of receipt of this Final Order an audit evaluating Enterprise's investigation of the corrosive effect of the hazardous liquid it transports by pipeline, in accordance with § 195.579. Based upon that audit, develop and submit a plan within 60 days of receipt of this Final Order for conducting internal corrosion surveys in accordance with § 195.579(a) and (c).

5. Maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and report the total cost as follows: (a) total cost associated with preparation, revision of plans and procedures, and performance of studies and analyses; and (b) total cost associated with physical changes, if any, to the pipeline infrastructure, including replacements and additions. Report this information when submitting documentation demonstrating compliance with each of the above items.

6. Complete each of the above items and submit documentation of compliance to the Director, Southwest Region, Office of Pipeline Safety, 8701 South Gessner Dr, Suite 1110, Houston, TX 77074-2949.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

Failure to comply with this Order may result in administrative assessment of civil penalties not to exceed $100,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

The Notice also proposed a compliance order with respect to Item 2 in the Notice for an alleged violation of § 195.410(a)(1). Since that allegation has been withdrawn, the associated compliance terms are not included in this order.

WARNING ITEM

With respect to **Item 3**, the Notice alleged a probable violation but did not propose a civil penalty or compliance order for the item. Therefore, this item is considered a warning item. The warning was for:

> **49 C.F.R. § 195.420(c)** – Respondent's alleged failure to have written procedures for specifying the method of protection for each valve from unauthorized operation and vandalism.[9] The Notice alleged Respondent did not have procedures for consistently specifying the method of security for valve sites, noting that Respondent used different levels of protection among valve sites, such as: no fencing or security; pipe posts and beam enclosures with locks; cyclone fencing with barbed wire; welded steel plate enclosures; and concrete covers.

Although warning items do not necessitate a response, Enterprise contested this allegation of probable violation. The company contended § 195.420(c) does not require that protection be uniform across all types of pipeline systems and valve locations. Respondent further contested the factual assertion that it had not provided protection at some locations, explaining that any location without fencing still had an appropriate level of protection from guardrails, locks, or other methods.

While I do not adjudicate warning items to determine if a violation occurred, I agree with Respondent that § 195.420(c) does not explicitly require uniform security methods across all valve locations. Different circumstances may warrant different levels of security and the performance-based requirement at § 195.420(c) recognizes this so long as an operator can justify its selection of certain protection methods.

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[9] *See also* § 195.402(c)(3), which requires operators to prepare and follow written procedures for conducting operations and maintenance activities in accordance with § 195.420(c), among other requirements.

The Notice further alleged, however, that Respondent did not have procedures for specifying the method of security for valve sites. Sections 195.420(c) and 195.402(c)(3) require operators to prepare and follow written procedures for determining the appropriate level of security. Respondent did not contest the allegation that it did not have procedures for determining the method of security for valve sites.

Accordingly, having considered the information in the record, pursuant to 49 C.F.R. § 190.205, I find a probable violation of 49 C.F.R. § 195.420(c) occurred and Respondent is hereby advised to correct such condition. In the event that PHMSA finds a violation of this item in a subsequent inspection, Respondent may be subject to future enforcement action.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of the petition automatically stays the payment of any civil penalty assessed. All other terms of the order, including any required corrective action, shall remain in full force and effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order shall be effective upon receipt.

For

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

DEC 02 2009

Date Issued