U.S. Department
of Transportation

**Research and
Special Programs
Administration**

400 Seventh St. S.W.
Washington, D.C. 20590

DEC 31 2003

Mr. Lon R. Trotter
Vice President
Corporate Services Division
Alyeska Pipeline Service Company
1835 South Bragaw Street
Anchorage, Alaska 99512

Re: CPF No. 5-2000-5006

Dear Mr. Trotter:

Enclosed is the Final Order issued by the Associate Administrator for Pipeline Safety in the above-referenced case. The Final Order makes findings of violation with respect to Items 1a, 2, 3a and 8 (Item # as alleged in the Notice of Probable Violation dated Feb. 10, 2000); withdraws the allegations of violation with respect to Items 1b, 3b, 6a and 7; specifies actions to be taken to comply with the pipeline safety regulations with respect to Items 2 and 8; and assesses a civil penalty of $62,500. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

cc: Lee Schoen
Sheila Bishop

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
WASHINGTON, DC

In the Matter of Alyeska Pipeline Service Company, Respondent.	)	CPF No. 5-2000-5006

FINAL ORDER

On April 14-18, September 13-18, and September 29-30, 1999, a representative of the Office of Pipeline Safety (OPS), pursuant to 49 U.S.C. § 60117, conducted on-site pipeline safety inspections of Respondent's facilities and records from Pump Station #1 to Fairbanks on the Trans Alaska Pipeline System (TAPS).

As a result of the inspections, the Director, Western Region, OPS, issued to Respondent, by letter dated February 10, 2000, a Notice of Probable Violation, Proposed Civil Penalty, Proposed Compliance Order and Notice of Amendment (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had violated 49 C.F.R. §§ 192.179(b), 192.463(a), 195.401, 195.406, 195.416(a), 195.416(c) and 195.420, proposed assessing a civil penalty of $75,000 for several of the alleged violations, and proposed that Respondent take certain measures to correct the alleged violations. The Notice also proposed, in accordance with 49 C.F.R. § 190.237, that Respondent amend its procedures for Operations, Maintenance and Emergencies.

Respondent responded to the Notice by letter dated April 14, 2000 (Response). Respondent contested the allegations, submitted detailed information to explain the allegations and reserved the right to a hearing. On November 7, 2000, Respondent requested a hearing and submitted further information to address the allegations. The hearing was held in the Western Region, OPS, on February 9, 2001. After the hearing, Respondent submitted a Closing Response dated March 19, 2001.

FINDINGS OF VIOLATION

Item 1 in the Notice alleged that Respondent had violated 49 C.F.R. § 192.179(b), that requires each sectionalizing block valve on a transmission line to be readily accessible and protected from tampering and damage and to be supported to prevent the settling of the valve or movement of the pipe. The Notice alleged that the mainline valve (MGV-6) on the fuel gas line was not protected from tampering and damage because it was located adjacent to the main highway but was not fenced or marked with signs. The Notice further alleged that the valve was leaning and not supported. At the hearing, OPS expressed concern about a vehicle backing into the valve or a hunter shooting at the valve because of the lack of fencing and signs.

In its Response and at the hearing, Respondent explained that the valve had not been fenced at the time of OPS's inspection because the valve was undergoing a planned maintenance. The maintenance took place from June - September 1999. Respondent said it had removed the fence because of the maintenance but that the valve was padlocked and secured during this time. Respondent further maintained that the line was not in danger of impact from vehicular traffic because the valve is located 68 feet from the highway and the highway ditch and tundra mounds create natural barriers. Respondent added that the location is remote and the highway has little traffic.

Respondent agreed that the valve had been leaning but maintained that it was adequately supported. Respondent said that as part of the maintenance, it re-bedded, insulated and backfilled the valve and pipeline and that the field measurements it took after exposing the pipe confirmed that no settlement had occurred.

Section 192.179(b) requires that the valve be protected from tampering and damage. The valve was not fenced from June to September 1999 while the maintenance was performed and, during this period, Respondent did not place warning signs near the valve. Although the valve was in a remote area and during maintenance was chained and locked, nothing was in place for several months to alert anyone to the presence of the valve. A padlock was some protection, but a warning barrier and sign placed near the valve would have provided further protection by alerting anyone in the area to the valve's presence. Accordingly, I find that Respondent violated 49 C.F.R. § 192.179(b).

As for the allegation that the valve was not supported, Respondent demonstrated that the valve, although leaning, was at all times properly supported. Therefore, I am withdrawing this allegation.

Item 2 alleged that Respondent had violated 49 C.F.R. § 192.463(a), which requires an operator's cathodic protection system to provide a level of cathodic protection to comply with one or more of the applicable criteria specified in Part 192's Appendix D. The Notice alleged that Respondent's fuel gas line piping inside Pump Station #1 did not have adequate cathodic protection.

Respondent argued that all of its regulated piping is either above ground and does not require cathodic protection, or is buried immediately downstream of the pig trap and conforms to all conditions of the agreement it entered into with OPS in 1996. Respondent maintained that this agreement exempts such piping from standard cathodic protection criteria. OPS contended that the agreement did not cover this piping.

Respondent further maintained that, for the buried piping at issue, there was only one low cathodic protection reading out of five readings in the data set. Respondent argued that its measurements on the line demonstrate that there was only one measurement location with a low reading (Test Point 14) and that location is in a frozen environment that poses little corrosion risk. Respondent presented data showing that in 1997, 1998 and 1999, the cathodic protection levels at the other four locations exceeded the -850mv criterion specified in Appendix D. OPS did not dispute this data.

The 1996 agreement referred to is an agreement signed between Respondent and a former OPS Western Regional Director for Respondent to adopt a risk-based approach for monitoring corrosion control. The agreement covers all 8-inch and 10-inch fuel gas line piping inside Pump Station 1 that can be internally inspected. The fuel gas line inside Pump Station 1 falls within the scope of the agreement. Under the agreement, Respondent was to patrol and perform leakage surveys, to record pipeline condition corrosion information, to maintain the cathodic protection system, and to obtain annual cathodic protection readings.

The agreement for the risk-based approach to corrosion control is not a waiver, pursuant to 49 U.S.C. § 60118, waiving Respondent's requirement to comply with the cathodic protection requirements of § 192.463. A waiver must go through public notice and opportunity for a hearing and is granted after the Associate Administrator for Pipeline Safety (through delegated authority from the Secretary of Transportation) determines that the waiver is consistent with public safety, and states the reasons for granting the waiver. The agreement did not go through public notice and comment. Because this agreement was not a legal waiver, the fuel gas piping inside Pump Station 1 had to be cathodically protected according to the requirements of § 192.463, i.e., the protection had to meet one of the specified Appendix D criteria. Respondent's data showed that Test Point 14 had low readings from 1997-1999. Accordingly, I find that there was a violation of 49 C.F.R. § 192.463 at the fifth measurement location, located downstream of the compressor.

If Respondent continues to believe that alternative corrosion control methods, in lieu of compliance with § 192.463, should be applied to the fuel gas line at Pump Station 1, Respondent must apply for a section 60118 waiver.

Item 3 alleged two violations of 49 C.F.R. § §195.401(a) and 195.401(b): that Respondent operated a section of the Trans Alaska Pipeline System at a level of safety lower than that required by the regulations, and did not correct two conditions (curvature and corrosion) within a reasonable time. The first allegation was that from 1992-1997, Respondent was aware that the Main Line Refrigeration Unit #2 (MLR2) was not adequate to prevent pipeline settlement and the pipeline had settled to 100% of critical curvature. (MLR2 provides refrigeration to the soil beneath the 1.8 mile segment of pipeline between MP 652.03 and MP 653.83.)

The second allegation in Item 3 was that Respondent was aware in 1991, when it excavated the pipe within the 1.8 mile segment, that the clam shell insulation surrounding the pipeline was damaged and saturated with water, and that because the pipeline was not cathodically protected, external corrosion would occur on the pipeline. The Notice alleged that Respondent confirmed this condition when it excavated a section of pipeline at MP 652.26 in 1999, and found serious corrosion caused by damaged and saturated insulation.

Respondent maintained that it had responded in a timely manner to maintain a level of pipeline safety required by the regulations and that during 1992-1997, it was engaged in monitoring, evaluating and mitigating the pipeline curvature and corrosion at MLR2. Respondent further contended that neither condition compromised the integrity of the pipeline.

Curvature

OPS contended that Respondent's turning off the refrigeration unit caused the pipeline to settle in thawed unstable soils in the area of MP 652.03 to 652.83, resulting in damage to the underground insulation.

Respondent maintained that it took action between 1992-1997 to address the curvature situation. Respondent said that it became aware in late 1991 that a portion of the pipeline at MLR2 had settled and that, beginning in 1992, took steps to monitor, evaluate and stabilize curvature resulting from settlement at MLR2. Respondent explained that these actions included -

- In February 1992, installing 13 thermistor strings to monitor soil temperature.
- Running a Geopig in 1992, twice in 1993, again in 1994 and 1995 to more accurately measure pipeline geometry. Respondent said the data from the first run revealed high curvature at MP 653.45, and in the subsequent runs, the readings showed no increase in the curvature piping.
- Running a deformation pig, which measures internal pipe radius, in 1992, 1995 and 1998. Respondent maintained that the data showed no wrinkles in the pipe wall near MP 652.03, or near MLR2.
- Installing 39 additional monitoring rods in 1992, an additional 3 in 1997, and monitoring the rods at least once each quarter. Respondent said that from June 1992 through December 1997 the monitoring showed little settlement.
- In 1993, adding an additional refrigeration unit to stabilize the permafrost soil beneath the pipe.
- In 1997, retaining an independent engineering consultant to assess the situation at MP 653.45. According to Respondent, the consultant reported that there had been modest changes in curvature but the curvatures were decreasing, and the most recently measured curvature was not an integrity concern.

In 1975, Respondent was granted a waiver from compliance with the coating and cathodic protection requirements in §§ 195.238(a)(5) and 195.242(a) on several sections of the TAPS. The 1.8-mile-mile section at issue is covered by the waiver. The waiver allowed Respondent to use special coating and refrigeration to safeguard the migratory animal crossings against thawing of the permafrost by the high temperatures of the buried pipe. OPS explained that thawing would reduce the support for the pipe and increase the likelihood of corrosion due to the presence of water. Although OPS expressly found that one of the reasons for allowing the waiver was that the refrigeration provided additional protection because it would prevent liquid water, and eliminate the likelihood for corrosive action, OPS did not make Respondent's maintaining the refrigeration an express condition of keeping the waiver. In 1986, Respondent turned off the mainline refrigeration units at MLR2, which caused pipeline settlement and damage to the underground insulation.

The waiver did not relieve Respondent of the requirement of § 195.401(b) to address an adverse condition on the pipeline within a reasonable time. Regardless of the cause, the pipe settled to 100% critical curvature. Between late 1991 and, early 1992, Respondent became aware that the pipeline at MLR2 had settled. The pig runs in 1992, 1993, 1994 and 1995 confirmed that the pipeline was at 100% critical curvature. In 1993, Respondent added additional refrigeration in an attempt to address the issue. The 1995 pig run again showed 100% critical curvature. Although Respondent monitored the condition, it did not take additional steps to attempt to correct the problem until it added more refrigeration in 1997. This was not correcting the curvature problem within a reasonable time.

Accordingly, I find that Respondent violated § 195.401(b) by not correcting within a reasonable time the pipeline curvature that resulted from settlement at MLR2.

Corrosion

OPS argued that the 1975 waiver was premised on the theory that the applied thermal insulation design would mitigate corrosion from occurring; therefore, if Respondent determined that the underground insulation was in a corrosive environment, Respondent had to add cathodic protection. OPS contended that Respondent knew in 1992, when it excavated pipe at the MLR2 site (around RGV 98A near MP 653.08), that the pipe was in a corrosive environment but did not install a sleeve and impressed current until 1999 when it found 60% wall loss at the girth weld at MP 652.46. OPS argued that Respondent knew the waiver was not valid because it knew the pipe was in a corrosive environment, and further, that once Respondent had knowledge of the corrosion on the segment, was required by § 195.416 to have added cathodic protection.

Respondent countered that the original 1975 waiver was not invalidated by the discovery of the damaged insulation during the 1991 excavation and that its obligation to cathodically protect the pipe was not triggered until the waiver was amended in 1995, and then only when injurious corrosion was detected. Respondent maintained that the waiver did not require it to anticipate corrosion.

Respondent further contended that although it met the waiver conditions, it, nevertheless, investigated corrosion mitigation methods. Respondent explained that the test holes excavated in 1991 did not show corrosion to be a problem, confirmed by the smart pig, which did not show anomalies at MP 652.46. Respondent explained that beginning in 1992, it took the following steps to monitor, evaluate and mitigate corrosion at MP 652.46.

- In 1992, re-evaluating the pig data using more stringent standards and finding one anomaly that indicated wall loss of less than 20%.

- In 1994, running a corrosion pig and monitoring the data. Respondent maintained that the pig detected 40% wall loss near a girth weld but Respondent determined that the anomalies did not warrant a corrosion dig.

- In 1995, conducting a study of corrosion mechanisms on below ground pipe that showed a calculated corrosion rate of 5 mills per year.

- In 1996, re-running the corrosion pig and finding no increase in pit depth at MP 652.46 since the 1994 run.

- In 1997, running a corrosion pig, analyzing the corroded region according to RSTRENG and determining it to be safe.

- In 1998, running a smart pig that found the axial length to be l[illegible] than reported in 1997, but within the range of safety.

- In 1999, excavating MP 652.46 and finding the wall loss to be approximately 65% of the original pipe thickness.

As previously discussed, OPS, in 1975, granted Respondent a waiver from the coating and cathodic protection requirements of §§ 195.238(a) and 195.242(a) on certain sections of thermally insulated mainline piping, that include the 1.8-mile segment at MLR2. One of the premises for OPS granting the waiver was that the applied design would mitigate corrosion from occurring under the insulation. In 1995, OPS amended the waiver because of information that the thermal insulation design had not prevented all corrosion from occurring. The amendment allowed Respondent to continue under the waiver subject to certain conditions. Respondent was to conduct annual internal inspection tool corrosion surveys capable of detecting and assessing potentially injurious corrosion. If the survey data indicated areas of potentially injurious corrosion, Respondent was to re-coat and cathodically protect the excavated piping to comply with §§ 195.238(a)(5) and 195.242(a).

In 1991-1992, Respondent found that the insulation surrounding the pipeline at MLR2 was damaged and the pipe was corroding. Respondent was aware that two bases on which the waiver was based were faulty - that the outer jacket would be a relatively impermeable barrier to moisture, and corrosion would be minimized because of other mitigating factors. However, the 1975 waiver did not provide that should a premise for the waiver prove faulty Respondent was to add cathodic protection, or that either OPS or Respondent revisit the basis for granting the waiver.

The 1995 amendment to the waiver required Respondent to run internal inspection tools capable of detecting corrosion. Respondent did so in 1996. According to Respondent the data showed no increase in pit depth from a run in 1994. Respondent ran a pig again in 1997, analyzed the corroded region at MP 652.46 and determined it to be safe under RSTRENG. When, in 1999, Respondent excavated the pipe at MP 652.46, it found the wall loss to be approximately 65% of the original pipe thickness, and installed a pipe sleeve.

The requirement to add cathodic protection did not take effect until injurious corrosion was found. According to Respondent this did not occur but Respondent, nonetheless, installed a permanent impressed current system. OPS did not dispute this contention or show that injurious corrosion occurred before 1999, prompting Respondent to apply cathodic protection. Thus, I do not find a basis for concluding that waiver required Respondent to apply cathodic protection to the corroded region before 1999.

However, the waiver did not exempt Respondent from compliance with § 195.401, which requires Respondent to operate its pipeline at the level of safety required by the regulations and to correct any adverse condition within a reasonable time. Corrosion is an adverse condition that can affect the safety and integrity of a pipeline. As previously discussed, Respondent evaluated and monitored corrosion at MLR2 between 1992-1999. Respondent voluntarily ran a corrosion pig in 1994, and detected wall loss near a girth weld. Morever, according to Respondent, the length of the anomaly did not warrant a corrosion dig under prevailing standards. According to Respondent the results of the additional pig runs and analyses did not show that additional action needed to be taken before 1999 to address the corrosion at MP 652.46. Under these circumstances, I cannot conclude that § 195.401 required more.

Respondent further maintained that the level of safety at MP 652.46 was never less than that required. Respondent explained that its hydraulics group determined that from 1992-1995, a pressure of 823 psi could have been reached, but that the maximum pressure would have been 750 psi. From 1995-2000, the corroded pipe at MP 652.46 could have withstood 855 psi with a safety factor of 1.39, but that the maximum pressure was 477 psi. OPS has not disputed this analysis.

I do not find that the evidence supports a finding that Respondent violated §§195.401(a) and 195.401(b) with respect to the corrosion at MLR 2, and am withdrawing the allegation.

Item 5 in the Notice alleged Respondent violated 49 C.F.R. §§ 195.406(a)-(b), when on October 16, 1999, a pressure relief event occurred at Pump Station 5 causing an over pressure of Check Valve No. V203. The regulation does not allow an operator to operate a pipeline at a pressure that exceeds the internal design pressure of the pipe or the design pressure of any other component of the pipeline. The regulation further requires an operator to provide adequate controls and protective equipment to control the pressure within the required limits. The Notice alleged that a similar event occurred at Pump Station 9 on September 12, 1995 causing an over pressure of Booster Pump Valve B20S. The Notice referenced two other over pressure situations (one in August 1997, one in August 1998) that had been the subject of another enforcement action (CPF No. 59502).

Respondent did not dispute that the over pressures had occurred but maintained that the two events cited in this Notice had fundamentally different root causes from the two that were the subject of

CPF No. 59502. Respondent maintained that the over pressures at Pump Stations 5 and 9 were the result of pressure pulses created by a vapor bubble. Respondent explained that at Pump Station 9, the vapor bubble was caused by inadequate refilling of piping that had been drained during a shutdown; at Pump Station 5, the vapor bubble was caused by closing the mainline relief valves too quickly. Respondent explained that the August 2, 1997 and August 5, 1998 over pressures cited in CPF No. 59502 resulted from human error at the Valdez Operations Control Center.

On September 12, 1995, at Pump Station 9, an over pressure of Booster Pump Valve B20S occurred. On October 16, 1999, at Pump Station 5, an over pressure of check valve No. V203 occurred. Accordingly, I find that Respondent violated 49 C.F.R. §§ 195.406(a)-(b) on these two occasions. I will discuss Respondent's response further in the penalty assessment and compliance order sections of this document.

Item 6 alleged that Respondent violated 49 C.F.R. § 195.416(a), which requires that an operator, at specified intervals, conduct tests on each pipeline facility under cathodic protection that is buried, in contact with the ground, or submerged, to determine if the cathodic protection is adequate. The Notice alleged that Relief Tank 190 did not have adequate cathodic protection because the cathodic protection levels did not meet the NACE -850mV or 100mV depolarization criteria required by NACE RPO 169.

Respondent maintained that Relief Tank 190 is cathodically protected and meets the current Part 195 cathodic protection requirements. OPS made the allegations of violation after it had inspected the tank in April 1999. In May 1999, a final rule took effect in which OPS adopted consensus industry standards regarding cathodic protection of aboveground petroleum storage tanks. The rule required compliance with the standards by October 2000. One of the standards OPS incorporated was API Recommended Practice 653 on Tank Inspection, Repair, Alteration and Reconstruction. OPS agrees that, under the API recommended practice, the cathodic protection on Tank 190 is adequate. Therefore, I will withdraw this allegation of violation.

Item 7 alleged that Respondent had exceeded the 2½-month inspection interval required by 49 C.F.R. § 195.416(c) on rectifiers 33-EE-123, 124, 125 and 127 at Pump Station 3[1], and rectifiers 36-EE-125 and 126 at Pump Station 6. The Notice alleged that the Pump Station 3 rectifiers had been inspected on April 27 and on August 14, 1999, and the Pump Station 6 rectifiers on February 25 and June 29, 1999. The Notice further alleged that rectifiers 35-EE-101, 103 and 104 at Pump Station 5 were not working properly.

Respondent maintained that the cited rectifiers were inspected within the required 2½-month intervals. Respondent submitted printouts from its computerized data management system, which showed that the four Pump Station 3 rectifiers were inspected on April 27, June 29 and August 14,

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[1]The Notice incorrectly cited Pump Station 1. The rectifiers at issue are located at Pump Station 3.

1999. Respondent maintained the information in the database is based on field records that are stored at various locations, or were misplaced, which is why the OPS inspector could not locate all of them. The printouts were corroborated with security logs from the pump station, which show that the inspector was at the pump station on those dates.

Respondent presented field records showing inspection dates for the two Pump Station 6 rectifiers of February 17, February 24-25, and June 29, 1999. Respondent argued that it was unlikely two inspections at Pump Station 6 had occurred in February and that the log entries were in error. Respondent maintained that its inspector had conducted the inspection on April 24-25, but had misdated the entry. Respondent said its computerized work order system confirmed that the inspection had actually occurred on April 24-25. Respondent also submitted copies of its security logs that show the rectifiers had been inspected in April 1999.

With respect to the malfunctioning rectifiers, Respondent said that its review showed no evidence of a fuse problem. Respondent said its records did not show any fuse replacements at 35-EE 103 and 104 at Pump Station 5, but that fuses were replaced at 35-EE-101 on several occasions. Respondent argued that there was no evidence of inadequate cathodic protection as a result of the blown fuses.

Respondent has demonstrated that it inspected the Pump Station 3 and 6 rectifiers within the required 2½-month intervals. Accordingly, I withdraw the allegation of violation. As for the alleged fuse problem at the three cited rectifiers at Pump Station 5, Respondent demonstrated that the fuses were working at rectifiers 35 EE-103 and 104. At rectifier 35 EE-101, there may have been a problem with fuses blowing, but OPS presented no evidence that this resulted in a pipeline safety violation. Accordingly, I withdraw this allegation of violation.

Item 8 alleged that Respondent violated 49 C.F.R. § 195.420(b) because it did not require function testing of the Battery Limit (BL) valves BL1 and BL2 at Pump Stations 2, 6, 8 and 10. The regulation requires mainline valves to be inspected at intervals not exceeding 7½ months, but at least twice each calendar year, to determine that the valves are functioning properly.

The Notice alleged that although the cited pump stations are not in service, the valves, nonetheless, must be maintained according to § 195.420(b) because they are located on the mainline pipe that runs through the manifold building at each pump station, act as pump station isolation valves and are subject to mainline flow and pressure. At the hearing, OPS expressed concern that the out-of-service BL valves at ramped-down pump stations could affect the worst-case scenario of oil spill response planning.

Respondent disagreed and argued that seven of the eight cited BL valves do not require biannual inspections because they were installed to permit isolation of pump station equipment, not as mainline valves to minimize damage or pollution from accidental discharge. Moreover, Respondent said the seven valves are not operational, and no longer function to isolate pump station equipment. Respondent explained that it treats pump station isolation valves as mainline valves in its procedural manual, and requires biannual testing when the valves are in service. In its closing response, Respondent added that it has never included the valves in its valve plan for minimizing damage or pollution from accidental discharge.

Respondent said the status of the eighth valve (BL1 at Pump Station 10) has changed and it now acts as a remote gate valve and operates on the mainline in a manner that would minimize damage or pollution. Respondent said it is inspecting this valve biannually.

I find that the remaining seven BL valves at issue are mainline valves. Although Respondent may not consider the valves as essential to minimizing damage from an accidental discharge, the valves, nonetheless, are located on either side of pump stations on the 48-inch mainline pipeline, and are subject to mainline flow and pressure. Crude oil flows continuously through the BL valves from Pump Station #1 to Valdez. As mainline valves, they must be inspected at the intervals required by § 195.420(b). Because Respondent has locked open the valves, it has not maintained the valves. Without stroking the valves at the required inspection intervals, Respondent has no way of knowing if they could close, if a situation ever warranted their closure.

Accordingly, I find that Respondent violated § 195.420(b) by not inspecting the seven BL valves at Pump Stations 2, 6, 8 and 10 at the specified intervals.

PENALTY ASSESSMENT

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 $75,000 for violation of §§ 195.401 and 195.406 (Items 3 and 5).

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: nature, circumstances, and gravity of the violation, degree of Respondent's culpability, history of Respondent's prior offenses, Respondent's ability to pay the penalty, good faith by Respondent in attempting to achieve compliance, the effect on Respondent's ability to continue in business, and such other matters as justice may require.

The Notice proposed a civil penalty of $25,000 for violation of 49 C.F.R. § 195.401 - operating a section of pipeline at a level of safety lower than that required by Part 195, and not correcting an adverse condition within a reasonable time. As discussed in the Findings section, there were two different allegations of violation. I found that Respondent had violated §195.401 for not correcting the curvature problem at MLR2 within a reasonable time, but withdrew the allegation of violation concerning the actions taken to address corrosion in the 1.8-mile segment. Respondent did not correct the curvature within a reasonable time. The pipe remained at 100% critical curvature - that is, it was at its maximum wrinkle bend potential - for an extended period until Respondent installed additional refrigeration. I find a civil penalty of $12,500 reasonable for this violation.

The Notice proposed a civil penalty of $50,000 for the over pressures of the line that were in violation of 49 C.F.R. § 195.406. Respondent objected to the amount of the proposed civil penalty. Respondent acknowledged that over pressure of the pipeline had occurred in 1995, 1997, 1998 and 1999 but that the two events that were the subject of this Notice had different causes from the two that were cited in another enforcement action. Respondent has demonstrated that the two cited in this Notice - the September 12, 1995 and October 16, 1999 events - were related to collapsing vapor bubbles in relief piping at pump stations and were distinct from those that were cited in CPF No. 59502. Nonetheless, two over pressure events occurred that had similar causes. Respondent did not take action to evaluate and address the cause for the 1995 over pressure. Had Respondent done so, a similar situation resulting from a vapor bubble might not have occurred in 1999. Both over pressures resulted in the leak of crude oil. I do not find a $50,000 civil penalty unreasonable in light of these facts.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a total civil penalty of $62,500.

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-120), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-4719.

Failure to pay the $62,500 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 an United States District Court.

WARNING ITEM

Item 6 in the Notice also alleged that three cathodic protection test stations at Pump Station 1 (RC20, 21 and 38) did not meet the NACE -850mV or 100mV depolarization criteria.

Respondent agreed that reference cells (RC) 20 and 21 in Box C showed low cathodic protection levels, but argued that the other three reference cells in that box show adequate cathodic protection. Respondent further maintained that although the RC 38 in Box D is defective, the other 15 reference cells in that Box show adequate cathodic protection. Respondent contended that, in any event, the environment in the insulated boxes is one that hinders corrosion and cathodic protection. Although the notice cited § 195.416(a), the issue is not whether Respondent was conducting tests at the required intervals to determine if the cathodic protection was adequate, but whether Respondent corrected the low potentials within a reasonable time, as required by § 195.401(b). Respondent has not been able to correct the low readings of reference cells 20 and 21 at Pump Station 1. OPS has confirmed that as of March 2002, reference cells 20 and 21 continue to be below criteria.

However, the Notice did not propose a civil penalty or compliance action with respect to this allegation of violation. Therefore, it is considered a warning item. Respondent is warned that it should take appropriate action to correct the low readings, or enforcement action can be taken if a subsequent inspection finds a violation.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to items 1, 2, 5, 6, 7 and 8.

For Item 1 (violation of 49 C.F.R. § 192.179(b)), the Notice proposed that Respondent take appropriate action to protect the facility from tampering and damage and to provide support for the valve to prevent settling.

Respondent documented that it has fenced the valve and re-installed the warning signs. Respondent has also modified its procedures to require the installation of warning barriers and warning signs when a fence is removed for valve maintenance. I withdrew the allegation concerning inadequate support of the valve because the valve was adequately supported. Therefore, no further action is necessary for Respondent to comply with this item.

With respect to Item 2 (violation of 49 C.F.R. § 192.463(a)), the Notice proposed that Respondent evaluate the cathodic protection on the fuel gas line piping inside Pump Station 1 and take appropriate action to bring the level of cathodic protection into compliance with one of the specified criteria. In its closing response, Respondent said that it would use one or more of the criteria in Appendix D to demonstrate the adequacy of cathodic protection on the buried portion of the fuel gas line within the Pump Station 1 fence. Respondent further said that the four rectifiers it added in 2000 to the mainline and bonded to the fuel gas line will raise the overall level of cathodic protection. The Region has confirmed that Respondent added the rectifiers but that the cathodic protection levels still do not meet either the -850mv or the 100 mv depolarization criteria. Therefore, this item will remain in a compliance order.

For Item 5 (violation of 49 C.F.R. § 195.406), the Notice proposed that Respondent evaluate the pipeline relief system at Pump Stations 5 and 9 for design deficiencies likely to cause over pressure of pipeline components and to take appropriate corrective actions based on the evaluation.

Respondent demonstrated that the September 12, 1995 and October 16, 1999 over pressures were distinct from those that occurred on August 2, 1997 and August 8, 1999. Respondent demonstrated that it has addressed the human error problems that led to the August 1997 and 1998 events by revising operating procedures and implementing additional controller training, modifying control logic to prevent restarting pumps with mainline valves not fully open, and updating Operations Control Center and pump station displays to improve valve status indications.

To address those events that were the subject of this enforcement action, Respondent explained that, inter alia, it has evaluated the relief system piping at all operating pump stations, changed its training and operating practices addressing piping refill, and replaced needle valves in the hydraulic circuit with orifices that will not drift open and let the relief valves close too quickly. The Western Regional Director is satisfied with the actions Respondent has taken and no further compliance action is required.

For Item 6 (violation of § 195.416(a)), the Notice proposed that Respondent evaluate the cathodic protection of Relief Tank 190 and take action to assure the tank is cathodically protected per the specified criteria. This allegation of violation was withdrawn, therefore, no further action is required.

For Item 7 (violation of § 195.416(c)) the Notice proposed that Respondent evaluate the operation of rectifiers 35-EE-101, 103, and 104 and take action to assure they operate reliably. I withdrew this allegation of violation, therefore, no further action is required.

For Item 8 (violation of §195.420(b)), further action is required with respect to the seven Block Mainline valves.

Under 49 U.S.C. § 60118(a), each person who owns or operates a 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, Respondent is hereby ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations.

1. Continue to evaluate the cathodic protection of the fuel gas line piping inside Pump Station 1. Take appropriate action to bring the level of cathodic protection at all measurement locations on the line into compliance with at least one of the applicable criteria specified in Appendix D of Part 192.

2. Conduct inspections at the intervals required in 49 C.F.R. § 195.420(b) for Block mainline valves BL1 and BL2 at Pump Stations 2, 6, 8 and 10. Amend your operating and maintenance procedures to provide that the valves are to be inspected in accordance with § 195.420(b).

3. Prepare an implementation plan and schedule to carry out each of the required items. Submit the plan and schedule within 30 days after receipt of this Final Order to the Western Regional Director. The Director must approve the plan and schedule.

AMENDMENT OF PROCEDURES

The Notice (Item 4) alleged inadequacies in Respondent's Procedural Manual for Operations, Maintenance and Emergencies (OM-1 document) and proposed that Respondent amend the document to include procedures for the new breakout tank requirements.

Respondent did not contest this allegation. Respondent explained that the new regulations on breakout tanks became effective in May 1999, with compliance required by October 2000, and Respondent had not yet updated its document before the OPS inspections in 1999. Respondent said it has since updated its manual to incorporate the new requirements.

Respondent submitted a copy of its amended procedures, which the Director, Western Region, OPS reviewed. Accordingly, based on the results of this review, I find that Respondent's original procedures as described in the Notice were inadequate to ensure safe operation of its pipeline system, but that Respondent has corrected the identified inadequacies. No need exists to issue an order directing amendment.

Under 49 C.F.R. § 190.215, Respondent has a right to 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 effect unless the Associate Administrator, upon request, grants a stay. The terms and conditions of this Final Order are effective upon receipt.

Stacey Gerard
Associate Administrator
for Pipeline Safety

12/31/03
Date Issued