U.S. Department
of Transportation

**Research and
Special Programs
Administration**

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

APR 28 2004

Mr. Robert Shoaf
Vice President
Regulatory Affairs
900 East Benson Boulevard
Alyeska Pipeline Service Company
Anchorage, AK 99508

Re: CPF No. 5-2002-5003

Dear Mr. Shoaf:

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 1, 4, and 5 (Item # as alleged in the Notice of Probable Violation dated February 7, 2002);
- withdraws the allegations of violation with respect to Items 2a and 7;
- makes a finding of inadequate procedures for Items 3a, 3b, 8a and 8b and requires amendment of those procedures
- withdraws the allegation of inadequate procedures for Item 3c and 8c;
- finds that you have completed the actions specified in Items 1and 4 required to comply with the pipeline safety regulations; and
- assesses a civil penalty of $45,000.

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: Sheila Doody Bishop
Attorney
P.O. Box 60469
Fairbanks, Alaska 99706

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEPARTMENT OF TRANSPORTATION
RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION
WASHINGTON, DC 20590

In the Matter of Alyeska Pipeline Service Company, Respondent.	CPF No. 5-2002-5003

FINAL ORDER

On July 17-28, September 13-17, October 7-17 and October 30-31, 2000, representatives 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 Valdez 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 7, 2002, 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. §§ 195.401(a), 195.402(a), 195.418(a), 195.422 and 195.428(a), proposed assessing a civil penalty of $80,000 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 March 8, 2002 (Response). Respondent did not contest one of the allegations (Item 5, § 195.422) and submitted payment for the proposed civil penalty via wire transfer. Respondent requested an extension to respond to the other allegations in the Notice. The Western Region granted an extension on March 15, 2002. On April 16, 2002, Respondent notified OPS that it was voiding the $25,000 check for the civil penalty amount and would include a response to Item 5 when it responded to the other allegations. On May 13, 2002, Respondent submitted its response to the Notice. Respondent contested the allegations, submitted information to address the allegations and reserved the right to a hearing if OPS did not withdraw the allegations based on the submitted information. An informal hearing was held in the Western Region, OPS, on April 8, 2003. After the hearing, Respondent submitted a Closing Response dated June 6, 2003.

FINDINGS OF VIOLATION

Item 1 in the Notice alleged that Respondent had violated 49 C.F.R. § 195.401(a), which provides that an operator may not operate or maintain its pipeline system at a level of safety lower than that required by subpart F (Operation and Maintenance) and by the procedures the operator is required to establish under § 195.402(a). The Notice alleged that Respondent had operated the pipeline unsafely from August 1999 to April 2000. According to the Notice, on August 22, 1999, Respondent had modified the opening logic of Remote Gate Valve (RGV) #31 at Milepost 170 to open at 100% during pipeline startup, and on November 13, 1999 and February 10, 2000, Respondent had experienced large magnitude, abnormal hydraulic pulses at RGV 31 during pipeline startup. The Notice further alleged that during start up on April 17, 2000, the rapid opening of the valve caused unstable flow conditions to occur, creating a vapor pocket collapse immediately south of RGV 31. This collapse caused the resultant pressure pulse to exert excessive hydraulic forces and movement of the pipeline, tripping pipeline anchors near Mile post 170, shearing off support bracket bolts on aboveground anchors and raising the pipeline pressure to 793 psi.

Respondent maintained that the pipeline was operated safely from August 1999 until April 2000 and that the aboveground pipe and support and anchoring system performed as designed. Respondent disagreed with the allegations that it had not experienced the large-magnitude pressure variations before modifying the opening logic of RGV 31, that the event on April 17, 2000 generated excessive hydraulic forces and that the modified opening logic resulted in excessive pressure pulses.

Respondent acknowledged that a pressure pulse occurred and that the modified opening logic of RGV 31 was responsible for an increase in the magnitude of the hydraulic surges in that area. However, Respondent explained that the aboveground pipe is designed to respond to seismic and hydraulic events by absorbing energy through movement of the support and anchoring system. Respondent maintained that the aboveground pipe has experienced movement due to hydraulic surges but none of the pressure surges, including the one on April 17, exceeded 110% of MOP or resulted in any damage to the pipeline. Respondent acknowledged that the aboveground pipe moved on its support and damaged the support system but argued that the pipeline remained supported and was undamaged. Respondent explained that the anchors were designed to prevent the pipeline from being subjected to forces above 105 kips.

The incident on April 17, 2000 was a bubble collapse that occurred at a slack line interface at MP 170. The PAULA program, which assessed the raised pressure at 109.8% of maximum operating pressure, assesses pressure pulses. However, this was not a high pressure pulse that can be analyzed by the PAULA surge model but a fast transient pressure bubble collapse. When a transient pressure spike occurs at startup, the pipeline and its components receive a significant shock. The shock cannot be measured by conventional hydraulic programs. Moreover, those pressure spikes were due to Respondent's own actions in modifying the opening logic of RGV 31. Respondent made the modification without analyzing the potential for surge. When a transient pressure spike occurs at startup, the pipeline and components receive a significant shock and are stressed beyond their metal ductility. The changing of the opening logic for RGV 31 caused the pipeline to be subject unnecessarily to high surge pressure events.

Although this was a fast transient pressure spike, the support system supported the aboveground pipeline as it had been designed to do for seismic and thermal events. The smashing of the honeycomb barriers was within the design as were the sliding bolts. But normal design was exceeded when the support bracket bolts on aboveground anchors were sheared off due to the force of between 120 and 130 kips.

Accordingly, I find that Respondent violated § 195.401(a), because the pipeline was operated unsafely between August 1999, when Respondent changed the opening logic for RGV 31 and April 17, 2000, when the incident involving the vapor pocket collapse occurred.

Item 2A alleged that Respondent violated 49 C.F.R. § 195.402(a) because it did not follow its procedures in excavating the pipeline at milepost 710.77 when a wall loss of 62% had been identified by a magnetic flux leakage (MFL) in-line inspection in 1992. Respondent's procedures require excavation of the anomaly if the penetration threshold exceeds 50% of nominal wall thickness, but Respondent did not excavate the pipeline until May 2000. The regulation requires an operator to prepare and follow for its pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies.

Respondent disagreed that it had knowledge of wall loss at this location in 1992 and that it had not followed its procedures in inspecting the anomaly. Respondent explained that the analysis of the 1992 MFL pig data identified a nonspecific indicator or pipeline feature at MP 710.7, but did not identify any wall loss with that feature. It was not until the smart pig inspection in 1998 and the 1999 data analysis from that run that a 43% wall loss was identified at that location. Respondent maintained that it took prompt action to excavate the location in May 2000 although the 43% corrosion wall loss did not match the criterion for required excavation. Respondent explained that when it excavated at the location, it found an actual wall loss of 60%.

Although the records, if the data had been analyzed correctly, may have showed the 60% wall loss before Respondent excavated the location in 2000, those charged with interpreting the data failed to identify the location as one requiring excavation under Respondent's procedures. Rather than a failure to follow procedures, the failure was in interpreting the data correctly and responding accordingly. Accordingly, I am withdrawing the allegation of violation.

Item 4 alleged that Respondent violated 49 C.F.R. § 195.418(a), which provides that an operator must not transport any hazardous liquid that would corrode the pipe or other components of its pipeline system unless the operator has investigated the corrosive effect of the hazardous liquid on the system and taken adequate steps to mitigate corrosion. The Notice alleged that Respondent had not investigated the internal corrosive effects of the hazardous liquids on its six-inch bypass piping on check valves 6, 7, 9, 13, 18, 29, 29A, 30, 68A and 71 although Respondent had noted substantial internal wall loss in underground check valves 4, 10, 12, 16, 17, 75, 83 and 84 and in the bypasses of aboveground check valves 19A, 32 and 37.

Respondent agreed that at the July 2000 inspection Respondent had not inspected all of the check valve bypasses. Respondent noted that in 1997 it had proposed a five-year schedule to excavate all the non-inspected buried check valves, and that it kept government agencies apprised of the status of its activities. Respondent stated that all check valves have now been inspected and there are procedures in place to ensure an adequate checking schedule.

Respondent did not have a 49 U.S.C. § 60118 (c) waiver from the requirement to investigate the internal corrosive effects of the hazardous liquids it was transporting on its check valve bypasses. Accordingly, I find that Respondent violated § 195.418(a) with respect to the cited check valves.

Item 5 alleged that Respondent had not insured repairs it made to its pipeline were made in a safe manner, in violation of 49 C.F.R. § 195.422(a). The Notice alleged that in excavating and examining severe mechanical damage at MP 710.76 on May 15, 2000, Respondent had bypassed pump station 12, which increased the pressure at the defect location from approximately 330 psig to approximately 670 psig. The Notice further alleged that because Respondent could not determine accurately the remaining wall strength at the location of the defect, Respondent should have lowered the pressure at the location, or at least not raised the pressure.

Respondent did not contest this allegation but explained that it had taken steps to ensure that in the future pressure is not raised on a known defect. Accordingly, I find that Respondent violated § 195.422(a) when it made this repair on May 15, 2000.

Item 7 alleged that Respondent violated 49 C.F.R. § 195.428(a) because Respondent could not provide records demonstrating the standard maintenance procedures for all pressure safety valves at Pump station 3 had been completed for calendar year 1999. Respondent's maintenance records showed that pressure safety valves 304 A, B and C and 305 A, B and C were scheduled for maintenance on October 30, 1999 but that Respondent did not inspect valves 304 A, B and C until November 2, 2000, valve 305A until October 24, 2000 and valves 305 B and C until September 16, 2000. The regulation requires an operator to inspect and test each pressure limiting device, relief valve, pressure regulator or other item of pressure control equipment to determine that it is functioning properly at intervals not exceeding 15 months, but at least once each calendar year.

Respondent contested this allegation and maintained that it had tested the Pump station 3 suction and discharge valves at the required interval in 1999. At the hearing Respondent provided documents (Model Work Orders and Preventive Maintenance Work Orders) demonstrating that it had inspected and tested the cited valves at the required intervals. The records showed that pump station valves 305A, B and C were tested on September 28, 1999 and that Pump station valves 304 A, B and C were tested on December 31, 1999, all within the required interval from the previous inspection and test. Accordingly, I am withdrawing this allegation of violation.

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 $80,000 for violation of §§ 195.401(a), 195.422 and 195. 428(a). (Items 1, 5 and 7.)

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(a) - operating the pipeline unsafely because of the modification of RGV 31's opening logic. Respondent acknowledged that the incident on April 17, 2000, was due to its having changed the valve's opening logic. The incident generated sufficient force to move the pipeline on its supports and to shear the anchors. Although it was fortunate the pipeline was not damaged, the pipeline, nonetheless, was stressed unnecessarily. As mitigating factors, Respondent noted that it had voluntarily notified OPS about the event and, on its own initiative, taken steps to identify the cause and reduce the magnitude of future surge events. I assess a civil penalty of $20,000 for this violation.

The Notice proposed a civil penalty of $25,000 for Respondent's violation of 49 C.F.R. § 195.422(a) for not ensuring that repairs made to the pipeline were done in a safe manner. Respondent said that it had implemented new procedures to avoid unsafe repairs in the future. I assess a civil penalty of $25,000 for this violation.

The Notice proposed a civil penalty of $30,000 for not testing the Pump station 3 valves at the required intervals. I withdrew this allegation of violation.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a total civil penalty of $45,000.

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-120), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-8893.

Failure to pay the $45,000 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.

WARNING ITEM

The Notice issued a warning for Item 2B - not following normal operating procedures in removing the RGV-35A control card for maintenance without requesting the Operation Control Center to inhibit the RGV control logic. Respondent said that its operator qualification program is structured to prevent a recurrence. Respondent is again warned that enforcement action will be taken if a subsequent inspection reveals a violation.

The Notice also issued a warning for Item 6 for exceeding the maximum pressure when moving an aboveground section on the pipeline. Respondent contended that the regulation did not apply because it was written for belowground pipe and Respondent's pipeline at Squirrel Creek is aboveground. Respondent stated that it is preparing a request for a waiver from the regulation. Respondent must ensure that, while the waiver is pending, it complies with § 195.424(a) by reducing pressure when moving any line pipe.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Items 1, 2A and 4. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601.

With respect to the violation of §195.401(a) (Item 1), the Notice proposed that Respondent provide an engineering/surge analysis and modify its start-up procedures. Respondent reported that it reviewed its records to determine what caused the largest pressure surge. It analyzed the April 17, 2000 event, recommended corrective action, and implemented a revised opening sequence for RGV 31.

With respect to the violation of §195.418(a) (Item 4), the Notice proposed that Respondent investigate the 6-inch bypass piping on the cited check valves for internal corrosion. Respondent reported that it had inspected all of its check valve bypass lines.

Accordingly, since compliance has been achieved with respect to these violations, the compliance terms are not included in this Order.

For Item 2A, the Notice proposed that Respondent integrate all of its pigging information to provide an engineering analysis on the condition of the Trans Alaska Pipeline System. Because I withdrew this allegation of violation, corrective action is not required.

AMENDMENT OF PROCEDURES

The Notice (Items 3 and 8) alleged inadequacies in Respondent's Procedural Manual for Operations, Maintenance and Emergencies and proposed to require amendment of Respondent's procedures to comply with the requirements of 49 C.F.R. §§ 195.416(j), 195.424, 195.428(d) and 195.432.

Item 3 of the Notice alleged that Respondent's procedures -

- did not ensure that the cathodic protection system for aboveground breakout tanks, where corrosion of the tank bottom is controlled by a cathodic protection system, is operated and maintained in accordance with API recommended practice 651. (Item 3a);
- did not address reducing pressure to a least 50% of maximum operating pressure before moving or leveling any aboveground crude oil piping (Item 3b);
- did not address overfill alarm testing and inspection of the grounding system during the five-year external inspection interval (Item 3c).

With respect to the first allegation about the inadequacy of its procedures, Respondent maintained that there is no requirement that API RP 651 be site specific or that Respondent provide detailed site specific procedures in its O&M manual. Respondent argued that it was adequate for its OM-1 and MP-166-3.20 (System Integrity Monitoring Program Procedures for Tank Monitoring) to reference API RP 651 in its entirety.

The Notice cited inadequacy of the tank monitoring procedures to comply with §195.416(j), which was moved into new § 195.573(d) as of October 2002. The requirement remained the same. The reference in Respondent's procedures is too broad to provide adequate instruction to employees. The procedure should give more specific instructions or, at least, reference the applicable sections and paragraphs in API 651.

As for the second allegation, Respondent argued that the requirement did not apply to aboveground pipe and that its procedures are adequate to ensure aboveground pipe movement safety. Respondent maintained that it is preparing a request for a waiver from this requirement. Until Respondent is granted the waiver, the requirement applies and Respondent's procedure must reflect the requirement for a pressure reduction before moving any of the piping, including that aboveground.

With respect to the third allegation, Respondent pointed out that the inspection occurred before the regulation became effective in October 2000. Accordingly, this allegation concerning Respondent's procedures is withdrawn.

Item 8 of the Notice alleged that Respondent's procedures for breakout tanks-

- did not specify an inspection interval of the lesser of five years or 1/4 corrosion rate life of the shell, as specified in API Standard 653 (Item 8a);
- did not require the Authorized Inspector's interaction and oversight of the inspection activities (8b); and
- did not address the requirements of subsection 11.3 of API RP 651 in its entirety (8c).

In response to the first allegation, Respondent maintained that it had inspected its breakout tanks in accordance with section 4 of API Standard 653 although the tank monitoring procedures listed the inspection frequency as five years. Respondent said that the standard had been incorporated by reference into its Tank Manual procedure TM -188.

Nothing in the record disputes Respondent's assertion that its inspection schedule considered the 1/4 shell corrosion rate. However, the allegation concerned whether that corrosion rate was specified in the procedure. The procedure Respondent submitted (TM-188, section 2.5) references API standard 653 when referring to a five-year inspection cycle. Although the 1/4 shell corrosion rate is in the standard, it should also be listed in the procedure to be absolutely clear about the length of the inspection cycle.

With respect to the second allegation in Item 8, Respondent submitted its procedures that specify a certified API 653 tank inspector is to perform the visual inspections. Further amendment of these procedures is not required.

The third allegation in Item 8 incorrectly referenced §195.432. The Notice should have cited the cathodic protection monitoring requirements for breakout tanks in §195.416(j) (now §195.573(d)). Thus, this allegation was covered by the allegation in Item 3A and need not be repeated.

Accordingly, I find that Respondent's procedures as described in Items 3a, 3b, 8a and 8b are inadequate to assure safe operation of its pipeline system. Respondent has satisfactorily amended its procedures to address the inadequacy cited in Item 8b. Pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237, Respondent is ordered to make the following changes to its procedures. Respondent must -

1. Amend its procedures for breakout tanks (Operations, Maintenance and Emergencies (OM-1) and System Integrity Monitoring Program Procedures, Tank Monitoring (MP166-3.20)) to provide adequate instruction to carry out §195.573(d)). The procedures must provide more specific information about the requirements of API Recommended Practice 651 that must be followed or must cite the specific sections and paragraphs of API Recommended Practice 651 that must be followed.

2. Amend the procedures in its Operations, Maintenance and Emergencies manual (OM-1) to specify that pressure must be reduced to at least 50% of maximum operating pressure before moving or leveling the aboveground pipeline.

3. Amend its procedures for breakout tanks (Tank Monitoring (TM-188) and System Integrity Monitoring Program Procedures, Tank Monitoring (MP166-3.20)) to specify that the inspection interval for breakout tanks is the lesser of five years or the 1/4 corrosion rate life of the shell.

4. Submit the amended procedures to the Western Regional Director, OPS within 30 days from issuance of this Order.

5. The Regional Director may extend the period for complying with the required items if the Respondent requests an extension and adequately justifies the reasons for the extension.

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 and amendment of procedures, 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

APR 28 2004
Date Issued