Alyeska pipeline SERVICE COMPANY
PO BOX 196660 ANCHORAGE, ALASKA 99519-6660 TELEPHONE (907) 787-8700

May 22, 2008

Government Letter No.: 16050
APSC File No. 2.11

Mr. Chris Hoidal, Western Region Director
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
12300 West Dakota Avenue, Suite 110
Lakewood, CO 80228

Re: Notice of Probable Violation CPF No. 5-2008-5002

Dear Mr. Hoidal:

Attached please find Alyeska Pipeline Service Company's detailed response to the Pipeline and Hazardous Materials Safety Administration's Notice of Probable Violation (NOPV) CPF No. 5-2008-5002, dated April 1, 2008.

Alyeska provides this information in response to this NOPV. Alyeska believes that this response will provide adequate clarification and additional information on the findings issued by PHMSA.

We hope you will find this material helpful. Should you have further questions, please do not hesitate to contact me at (907) 787-8061.

Sincerely,

Joseph P. Robertson

Joseph P. Robertson, P.E.
JPO/ DOT Liaison Director

JR/leb

Attachment: Alyeska Pipeline Service Company's Response to NOPV CPF 5-2008-5002.

cc: Jon Strawn
Jerry L. Brossia
Dennis Hinnah
Mike Thompson
JPO Records Center

CERTIFIED MAIL 7002 2410 0005 0102 9689

PROBABLE VIOLATION 1:
Valves

PHMSA POSITION

Pertinent Regulation:
49 CFR §195.116 Valves. Each valve installed in a pipeline system must comply with the following:

(e) Each valve other than a check valve must be equipped with a means for clearly indicating the position of the valve (open, closed, etc.).

Findings:
During the inspection, MGV 10A was found without a valve position indicator.

Evidence:
Photograph of MGV 10A without valve position indicator.

Proposed Compliance Order:
In regard to Item Number 1 of the Notice pertaining to the missing valve position indicator on MGV 10A, Alyeska Pipeline Service Company shall install a valve position indicator on MGV 10A.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) does not contest this finding. Alyeska has scheduled the installation of a valve position indicator on MGV 10A to be completed by June 30, 2008.

Discussion:
Valve MGV-10A has a non-standard stem nut which causes the stem to only be visible and indicate valve position from about 90%-100% open. Alyeska has written a work order for the Maintenance Team to install a valve position indicator at MGV 10A (see Exhibit 1) no later than June 30, 2008.

SUPPORTING DOCUMENTATION

Exhibit 1 -- Work Order 38009356

Facility: P/L PIPELINE/ROW WORK MGMT. UNITS
Unit : MLPIPE Project :
Ref Type: WR Ref No.: 38001987
W/O Type: CO Group : LWMT W/O Dspln : M
Planner : U176586 HOFFMAN L
W/O Title : MGV-10A,STEM EXTENSION,INSTALL
W/O Task Title: MGV-10A,M,STEM EXTENSION,INSTALL
Written To : MANUAL GATE VALVE - 48" MAINLINE
Task Dspln : M Task Pri: 03 Need Date: 06/30/08

Work Order Package

38009356 01

Rpt : TIPMC11
Date: 05/15/08

READY
Page: 1

Work Order Task Written To

Facility :	P/L	Unit :	MLPIPE	Op Sys :	
Division :	20	Area :	PIPE	Sys/Cls:	VALVE
Equipment :	VALV MGV-10A	Component:			
Work Item :		Eqt. List:		Ops Review Reqd:	
Equip. Tag:	20-MGV-10A	Alt:			
UTC :		Tbl/Brkdwn:	(Past 12 mo)		
Catalog ID:		Job Type :	CV	UCR:	
Client/Act:					
Location :		MP - 40.54	BELOW GROUND		
Cost Centr:	811011	Activity :		User Def:	
Percentage:	100.000	Acct No. :	GL 400	003	

Work Order Task Instructions

A NOPV CPF 5-2008-5002 WAS RECEIVED APRIL 1, 2008. MGV 10A WAS CITED AS NOT BEING EQUIPPED WITH A MEANS FOR CLEARLY INDICATING THE POSTION OF THE VALVE. THIS VALVE HAS AN EXTENDED STEM NUT BECAUSE IT IS BURIED DEEPER THAN MOST VALVES. A SIGNIFICANT AMOUNT OF WORK WAS PERFORMED IN 2003 TO INSTALL CLEAR STEM COVERS ON ALL GATE VALVES LINEWIDE. THIS VALVE HAD A CLEAR STEM COVER INSTALLED BUT WITH ONLY ABOUT 12 INCHES OF THE STEM VISABLE THERE IS NO WAY TO KNOW THE VALVE POSITION ONCE THE VALVE CLOSES BEYOND THIS POINT. THE WORK IN 2003 WAS DONE UNDER WO 33002455. THIS WORK ORDER CONTAINS THE BULK OF THE INFORMATION REQUIRED TO CORRECT MGV 10A. RUSS BONAR WAS INVOLVED IN THE INITIAL INSTALLATION AND WILL WORK WITH THE LWMT TO DETERMINE MATERIAL REQUIREMENTS. THE NEW INSTALLATION WILL REQUIRE 4" ABS BLACK PIPE TO BE ATTACHED TO THE STOP OF THE STEM FOR 100% VISUAL INDICATION OF VALVE POSITION. THIS IS A HIGH PRIORITY REPAIR SINCE IT IS PART OF A NOPV COMPLIANCE ORDER.

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ORIG WR INFO:
TITLE = INSTALL VISUAL STEM EXTENSION AT MGV 10A

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SEE GDOC FOR PLANNING/ENGINEERING DISPOSITION OF CODE VIOLATIONS, ETC.

QC Requirements/Comments

NO QC REQUIREMENTS FOR THE WORK ORDER TASK

Facility: P/L PIPELINE/ROW WORK MGMT. UNITS
Unit : MLPIPE Project :
Ref Type: WR Ref No.: 38001987
W/O Type: CO Group : LWMT W/O Dspln : M
Planner : U176586 HOFFMAN L
W/O Title : MGV-10A,STEM EXTENSION,INSTALL
W/O Task Title: MGV-10A,M,STEM EXTENSION,INSTALL
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38009356 01

Rpt : TIPMC11
Date: 05/15/08

Alyeska pipeline

READY
Page: 2

QC Requirements/Comments

References/Document Information

Type/Subtyp:	GDOC	Number: 001	Sheet:	
Title/Desc :	PLANNING EMAILS		Image:	N
Type/Subtyp:	GDOC	Number: 002	Sheet:	
Title/Desc :	STEM EXTENSION DRAWING		Image:	N
Type/Subtyp:	GDOC	Number: 003	Sheet:	
Title/Desc :	MGV ADAPTER PLATE DRAWING		Image:	N
Type/Subtyp:	GDOC	Number: 004	Sheet:	
Title/Desc :	RIK		Image:	N

Work Completion Signatures

Name/Badge	Function/Dept.	Date/Hours Worked

Specification Data (Predefined/Predictive Readings)

Operating Factors	Low Trigger	High Trigger	Normal	Current	Per Unit
BLOCK & BLEED CLOSED	.0000	.0000	1.0000		TYP
BLOCK & BLEED OPEN	.0000	.0000	1.0000		TYP
BHF(S) DS TOOK LUBE	.0000	.0000	1.0000		NUM
BHF(S) US TOOK LUBE	.0000	.0000	1.0000		NUM
DIFF PSIG ACROSS VLV	.0000	.0000	.0000		PSI
GLYCOL DRAINED GALS	.0000	.0000	.0000		GAL
LEAK THROUGH (NORM)	.0000	.0000	.0000		GPM
LEAK THRU AREA SQIN	.0000	.0000	.7000		SQI
PRESURD STEM PAC Y/N	.0000	.0000	2.0000		TYP
STEM LEAK DETECT Y/N	.0000	.0000	2.0000		TYP
REPLACE STEM PAC Y/N	.0000	.0000	2.0000		TYP
WATER DRAINED GALS	.0000	.0000	.0000		GAL

Facility: P/L PIPELINE/ROW WORK MGMT. UNITS
Unit : MLPIPE Project :
Ref Type: WR Ref No.: 38001987
W/O Type: CO Group : LWMT W/O Dspln : M
Planner : U176586 HOFFMAN L
W/O Title : MGV-10A, STEM EXTENSION, INSTALL
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Work Order Package

38009356 01

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Date: 05/15/08

Alyeska pipeline

READY
Page: 3

Print Request - Work Order Documents

Facility	Type/Subtype	Document Number	Sheet	Image Addr
P/L	GDOC	001 PLANNING EMAILS		
P/L	GDOC	002 STEM EXTENSION DRAWING		
P/L	GDOC	003 MGV ADAPTER PLATE DRAWING		
P/L	GDOC	004 RIK		

Completion Comments on Work Performed

COMMENTS:

***** END OF REPORT *****

PROBABLE VIOLATION 2:
Operation and Maintenance

PHMSA POSITION

Pertinent Regulation:

49 CFR §195.401 General Requirements

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

Findings:
A structural (non-pressure containment) sleeve was installed in 1990 at Mile Post (MP) 57.785, due to internal corrosion. Alyeska is operating the pipeline with an indeterminate amount of remaining pipe wall thickness under this sleeve. Alyeska did not correct this condition within a reasonable time even though a commitment to cut out and replace was made for 2007.

A 15-foot structural (non-pressure containment) sleeve was installed in 1990 at MP 57.785 due to internal corrosion. Alyeska monitored the corrosion at this location with Ultrasonic Testing (UT) pigs to determine the depth of corrosion until 2001. At that time, Alyeska determined that wax was blocking the ability of the UT pig to accurately predict the corrosion depth. In 2004, a Magnetic flux pig was run and it also was unable to accurately assess the corrosion depth. Alyeska is operating the pipeline with an indeterminate amount of remaining pipe wall thickness under a sleeve design that cannot contain pressure. Alyeska did not correct this condition within a reasonable time. This issue was reported to Alyeska in January 2006 and APSC management committed to PHMSA they would cut out this sleeve in 2007. Alyeska has now postponed this work until 2008 or 2009. This is not correction of a condition within a reasonable time.

Evidence:
1. Safety Related Condition Report 890028 Report listing internal corrosion as the cause, with maximum pit depth, 177.
2. Alyeska as-built database, listing 15 foot structural sleeve. (Not a pressure containing sleeve. A structural sleeve will not stop crude oil from leaking onto the ground, when the internal corrosion eats through the pipe wall).
3. Alyeska repair procedure for internal corrosion requires a pressure containing sleeve or replacement of pipe.
4. UT Pig data 1994-2001. (2001 pig having trouble with wax at Station 305116.6).
5. 2003 BJ MFL Pig did not report any corrosion at sleeve, due to the additional metal thickness of the sleeve.

Proposed Compliance Order:
In regard to Item Number 2 of the Notice pertaining to the structural sleeve at MP 57.785, Alyeska Pipeline Service Company shall remove and inspect the internal corrosion inside the pipe under the sleeve during the Pump Station 2 pipe replacement now scheduled for 2008. PHMSA shall be notified immediately if this sleeve is not removed in 2008.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) does not contest this finding. Alyeska will remove and inspect the structural sleeve referenced above this summer as part of the main line reroute at Pump Station (PS) 02. That section of pipe will be replaced as part of the reroute project.

Discussion:
The project for the PS02 Main Line Reroute is for installation of new mainline pipe from upstream of the BL1 valve to downstream of the BL2 valve. Cutover to this new pipe will take place during implementation of this project. The existing main line pipe will be cleaned and abandoned in place (see Exhibit 2).

The structural sleeve at MP 57.785 is installed between mainline valves M1 and M2 in an above ground section of pipe. As part of this reroute project, both M1 and M2 valves will be removed. The sleeved section of pipe will then be available for both internal and external inspection. Inspection of this section of pipe is included as part of the project.

With regard to Finding 2, Alyeska respectfully requests that PHMSA withdraw the proposed compliance order as the pipe under the sleeve at MP 57.785 is scheduled for removal and inspection this summer and the mainline pipe will be replaced as part of the reroute.

SUPPORTING DOCUMENTATION

Exhibit 2 -- PWR W010, PS02 Mainline Reroute

APSC Projects

Print Close

PS-02 Main Line Reroute

PWR Number: W010
From Initiator PWR Data
PWR Status: Implementation

Submitted By:	DOBBERPUHL, DAVID R	Employee No:	182139
Date Submitted:	12/5/2007	PWR for Location/Facility:	PS 2

Problem/Need Description:

This project involves the replacement of 1700 lineal feet of mainline piping above ground through Pump Station #2. The project will require fabrication of some shoes and supports in Fairbanks with additional fabrication planned for the PS02 site. Most of the new pipe will be supported on steel beam sleepers similar to the design at the Denali Fault. At some locations VSMs will be required for structural support. The Main Line pipe will be cut North of the BL 1 valve and South of the BL2 valve to tie into the horizontal section of the pipe. The existing pipe will be cleaned and abandoned in place. A temperature sensor, pressure sensor and pig passage detection will be installed on the new section of mainline. Controls will be installed to the control building and wired to the OCC in a subsequent project. A 48 inch split tee will be installed south of BL-2 for the installation of 48 inch TDW Stopple. BL-2 and the isolation fitting will be removed and sent to Fairbanks to be inspected and overhauled as directed. Insulation will be installed below the grade beams and in locations of new gravel pad on the north end. There will be 2 anchors for this new section of pipe. The pipeline will be insulated and jacketed and will maintain 2 feet minimal ground clearance. The final mainline reroute philosophy is to leave a clear 50 foot wide swath through the station along the mainline. The clearance will be 25 feet on either side of the mainline, allowing a clear zone for the future salvage contractor. No access will be provided within this contract for tank 120. Access will be addressed at the time of demolition.

Possible Alternative(s):

1-Do Nothing-This option is not recommended since the station is no longer needed and various portions of the existing station need continued maintenance. Not recommended. 2-Option A would simply replace the approximately 200' of ML pipe through the manifold area with a new piece of pipe without connections. The buried corridor will be filled in and the insulated boxes will be removed. 3-Option B would remode the piping from upstream of the suction LEFM to downstream of the transition south of BL2. This eliminates the issues around the buried corridor, the south insulated box, pulls an isolation fitting that can be examined, removes the maintenance and leak risk of BL2 and resolves settlement risks on all buried pipe on the south side of the Station. 4-Option C In late 2003, the Project team looked at the buried option. At that time we considered a new buried line from just inside the BL valves. Now knowing the CP systems are failing in the insulated boxes, we need to extend the buried section from upstream transition to downstream transition. This will require the installation of a stopple on the downstream end. 5-Option D would remode the piping from upstream of the BL1 transition to downstream of the transition south of BL2. In addition to eliminating the issues mentioned above for Option C, this option would also address the issue of settlement on the upstream transition.

Proposed Solution(s):

The recommended solution is to follow the plan for Option D above. Option D provides for a new above ground route from upstream of BL 1 to downstream of BL 2. The piping for the new route will be laid on sleepers similar to the Denali Fault location. Existing piping will be cleaned and abandoned in place. One BL valve will be removed and returned to Fairbanks for inspection of the isolation fitting.

Is a conceptual study Recommended?	No	Yes	Already Completed
Has a PWR already been assigned to this request?		No	Yes, PWR no: W010

Commitment

NOPV Response CPF 5-2008-5002
Exhibit 2
Page 1 of 5

Is this a commitment? No Yes, identify to whom: Strategic Long Range Plan

Commitment Priority: High Medium Low Commitment No: TBD

Identify Manager who made commitment: David Wight

Describe Commitment:

The long range plan addresses various the removal of certain stations from the mainline system by straight pipeing through the stations. PS-12 was the first to begin this process and was done in 2005. A plan is in place to complete the rest of the similar stations (PSs 6,7,8,10 and 11).

Regulatory/Safety/Environmental Condition

Is this request intended to resolve/mitigate a regulatory/safety/environment condition? No

Yes

Facilities/Equipment Condition

Is the facility or equipment in a failed state? N/A No Yes

Can the facility or equipment be used for its intended purpose? N/A No

Yes

Would this repair, replace or install a non-redundant protective device? No Yes

Would this repair, replace or install a redundant protective device? No Yes

Would this implement an endorsed recommendation resulting from a RCM analysis?

No Yes, identify title, date of RCM analysis and recommendation number:

Does the facility or equipment require frequent repairs?

No Yes, identify the frequency, typical down times and repair costs:

Is the equipment or facility approaching the end of its useful life?

No Yes, identify:

The station is no longer needed and can be retired from service. The Long Range Plan is not to need this station in future pipeline operation.

Is this request intended to mitigate/resolve emerging maintenance issues due to obsolescence or projected deterioration of otherwise functioning facilities/equipment?

No Yes, identify:

Eliminating various valves and below ground pipeline items, reduces risk and future maintenance.

Economics/Strategic Vision/Long Range Plan

Estimate Basis: unknown best guess historical experience

Recommended Plan Year: 2007

Financial: (amounts represented are in thousands of dollars)

Prior years spend:	Capital: $		Expense: $	Retirement: $
Plan year request:	Capital: $		Expense: $	Retirement: $
Plan year +1 request:	Capital: $	9,600	Expense: $	Retirement: $
Plan year +2 request:	Capital: $		Expense: $	Retirement: $
Plan year +3 request:	Capital: $		Expense: $	Retirement: $
Total Project Spend:	Capital: $	9,600	Expense: $	Retirement: $

Would this have a rate of return? Unknown No Yes

Estimated rate of return: %

Estimated payback period: Years Unknown

NOPV Response CPF 5-2008-5002
Exhibit 2
Page 2 of 5

Is this identified in the last approved Long Range Strategic Plan?

Unknown No Yes, Identify budget year(s): 2008

Describe how this aligns with Alyeska's Strategic Vision:
This project was included to be isolated in 2008.

File Attachments:

File Name	Uploaded by	Date Uploaded

Supervisor Decision (Gate 1):

Supervisor Name:	BALDRIDGE, JOHN D	Badge Number:	134155

Supervisor Decision:

- Endorsed and routed to Review Board
- Rejected, better suited for a maintenance (Passport) work request
- Rejected for insufficient information
- Rejected for insufficient business drivers

Decision Date: 12/5/2007

Supervisor Comments:

Review Board Decision (Gate 1):

Endorsed
- Conceptual Study is recommended
- Conceptual Study is required (Gate 1B)

Reject
- Cancel - Not Recommended for Re-Submittal

Rejection Reason:

- Rejected for insufficient information
- Rejected for insufficient business drivers
- Rejected for unclear alignment with the Long Range Plan
- Rejected for not being a project activity
- Other:

Decision Date: 2/25/2008

Review Board Comments:

Requesting / Receiving Manager:	BALDRIDGE, JOHN D	Badge Number:	134155
Executive Sponsor:	JOHNSON, JAMES F	Badge Number:	154807
Recommended Plan Year:		2007	
Recommended Implementation Year:		2007	
Identified Funding Source:		Project Budget Program Future Years Engineering End-Item Purchase Other:	
Assigned Project Manager:	DOBBERPUHL, DAVID R	Badge Number:	182139
Assigned Project Technical Lead:	KORSHIN, MATTHEW HARRI	Badge Number:	183947
Assigned Implementation Lead:	ADAMCZAK, CAROL WHITE	Badge Number:	184008
Assigned PWR Number:	W010		

NOPV Response CPF 5-2008-5002
Exhibit 2
Page 3 of 5

Review Board Decision (Gate 1B):

Endorsed — Conceptual Study is recommended

Reject — Cancel - Not Recommended for Re-Submittal

Return to Evaluation/Conceptual (Gate 1)

Rejection Reason:

Rejected for insufficient information

Rejected for insufficient business drivers

Rejected for unclear alignment with the Long Range Plan

Rejected for not being a project activity

Other:

Decision Date:

Review Board Comments:

Review Board Decision (Gate 2):

Endorsed — Conceptual Study Received

Reject — Cancel - Not Recommended for Re-Submittal

Return to Evaluation/Preliminary (Gate 1/1B)

Rejection Reason:

Rejected for insufficient information

Rejected for insufficient business drivers

Rejected for unclear alignment with the Long Range Plan

Rejected for not being a project activity

Other:

Decision Date: 10/11/2006

Review Board Comments:
10/11/06 Move through Gate 2 to P&D. Replaces F263.

Project Priority Score:

	Initiator	Evaluation
Total Points:	**50 points**	**50 points**

Financial: (amounts represented are in thousands of dollars)

Total Capital:	$	9,600
Total Expense:	$	
Total Retirement:	$	
Total Estimate:	$	9,600

NOPV Response CPF 5-2008-5002
Exhibit 2
Page 4 of 5

Identified Funding Source for Planning and Development:

Authorized Funding for Long Lead items: No Yes, identify:

Review Board Decision (Gate 3):

Endorsed

Reject — Cancel - Not Recommended for Re-Submittal

Return to Planning and Development (Gate 2)

Rejection Reason:

Rejected for insufficient information

Rejected for insufficient business drivers

Rejected for unclear alignment with the Long Range Plan

Rejected for not being a project activity

Other:

Decision Date: 2/26/2008

Review Board Comments:
1/23/08 Board agreed to move to Gate 3

Financial: (amounts represented are in thousands of dollars)

Total Capital:	$	9,600
Total Expense:	$	
Total Retirement:	$	
Total Estimate:	$	9,600

Print Close

last updated:July 09, 2003 contact: Help Desk

NOPV Response CPF 5-2008-5002
Exhibit 2
Page 5 of 5

PROBABLE VIOLATION 3:
Maximum Operating Pressure

PHMSA POSITION

Pertinent Regulation:
49 CFR §195.406 Maximum Operating Pressure

> (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.

Findings:
Alyeska's Sadlerochit meter piping at Pump Station 1 has a maximum operating pressure (MOP) of 275 psig (150 ANSI class,) and BP's incoming piping to the meter has MOP up to 740 psig (300 ANSI class). BP's surge report stated that BP's maximum discharge pressure has been limited by pressure shutdown switches at GC-1, FS-1 and FS-3. Alyeska must provide adequate controls and protective equipment to control the pressure within the maximum operating pressure. If BP switches are utilized, they must be maintained as DOT critical safety devices. Alyeska's "OM-1, Procedural Manual for Operations, Maintenance and Emergencies," Section 7 does not indicate that Alyeska must test and maintain these pressure switches.

Evidence:
1. In Alyeska's response to request for specific information, it is stated that Alyeska meter runs WOA & EOA (Sadlerochit oil) has a MOP of 275 psig.
2. BP's surge analysis report, Executive Summary, states that the high pressure switches are DOT critical safety devices.
3. OM-1 Section 2, surge pressure control, does not list high pressure switches at GC2, FS1, and FS3.

Proposed Compliance Order:
In regard to Item Number 3 of the Notice pertaining to the pressure shutdown switches at GC-1, FS-1 and FS-3. Alyeska shall maintain these pressure shutdown switches as DOT critical safety devices or shall install adequate pressure control equipment within its own facilities at Pump Station 1.

Alyeska Pipeline Service Company shall revise "OM-1, Procedural Manual for Operations, Maintenance and Emergencies," Section 7, to indicate that these pressure shutdown switches are DOT critical safety devices or to reflect any additional pressure control equipment Alyeska installs at its own facilities at Pump Station 1. Alyeska shall also arrange to have such pressure shutdown switches and any additional pressure control equipment tested annually and shall maintain and make available to PHMSA the records of such testing.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) respectfully disagrees with PHMSA's finding that pressure shutdown switches at GC-1, FS-1 and FS-3 must be maintained as DOT critical safety devices. The 36" Prudhoe Bay connection piping is operated by Alyeska as a low stress pipeline. As such, the line falls within the exception to applicability in §195.1(b)(3)(i) and is not regulated by PHMSA. Therefore, the pressure shutdown switches that protect the line are not regulated by PHMSA under 49 CFR Part 195. Alyeska requests that PHMSA withdraw this finding and the proposed compliance order.

Discussion:
The Prudhoe Bay production unit connects to TAPS at the point of the welded pipe joint upstream of the insulating flange at the area of change in pipe diameter, from 34" pipe to 36" pipe. The section of pipe, including the meter piping, operated by Alyeska is referred to as the Prudhoe Bay connection piping.

Alyeska operates the Prudhoe Bay connection piping and associated meter piping as a low stress pipeline. According to §195.2, Definitions, low stress pipeline means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength (SMYS) of the pipe.

The pipe installed for the Prudhoe Bay connection piping and meter piping is either 36" diameter, 0.375-inch wall, API-5LX-X60 or 36" diameter, 0.500-inch wall, API-5LX-X60 (see Exhibit 3). As specified in Alyeska's Piping Material Line Class Specification, 72% of SMYS for these pipes are 900 and 1200 psi, respectively (see Exhibits 4 (Table 1C) and 5 (Table 1A)). Using this information, 20% of SMYS for each pipe type is 250 and 333 psi, respectively. The piping is normally operated at a pressure below 100 psi. It is never operated at a pressure above 140 psi because that is the pressure the natural gas liquids (NGL) line would be shut in at Skid 50 (the Prudhoe Bay pipeline facility) across the road from Alyeska's Pump Station 1. Therefore, the Prudhoe Bay connection piping and meter piping are operated in their entirety at a stress level well below 20 percent of the SMYS of the pipe.

Low stress pipelines are exempt from the applicability of Part 195 when the low stress pipeline is an onshore pipeline that does not transport HVL, is located in a rural area, and is located outside a waterway currently used for commercial navigation. 49 CFR §195.1(b)(3)(i). The Prudhoe Bay connection piping transports hazardous liquid, not HVL. It is in a rural area, as defined in §195.2 as outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development. It is not located near a commercially navigable waterway. Therefore, the Prudhoe Bay connection piping meets all these criteria. Additionally, the 34" portion of the line, operated by BPXA, is operated as a low stress pipeline, so the line, in its entirety, is operated as a low stress line. Therefore, the Prudhoe Bay connection piping, including the meter piping, is not regulated by PHMSA under 49 CFR Part 195.

Section 195.406(b) requires adequate controls and protective equipment to control pressure from exceeding 110% of the maximum operating pressure for pipelines regulated by Part 195. As a low stress pipeline, the Prudhoe Bay connection piping and meter piping are not subject to the operating requirements of Part 195. The pressure shutdown switches, GC-1, FS-1 and FS-3, are used to protect the Prudhoe Bay connection piping from an overpressure event. However, the switches do not have to be maintained as DOT critical safety devices under §195.406(b) if the pipeline being protected is not regulated by PHMSA.

With regard to Finding 3, Alyeska respectfully requests that PHMSA withdraw the finding and the proposed compliance order because the Prudhoe Bay connection piping is operated as low stress pipeline and is not regulated by PHMSA under 49 CFR Part 195.

SUPPORTING DOCUMENTATION

Exhibit 3 -- Sadlerochit Fabrication Drawings
Exhibit 4 -- Specification P-503 Piping Material Line Class Specification, Table 1C – AT Line Class
Exhibit 5 -- Specification P-503 Piping Material Line Class Specification, Table 1A – FT Line Class

FLUOR

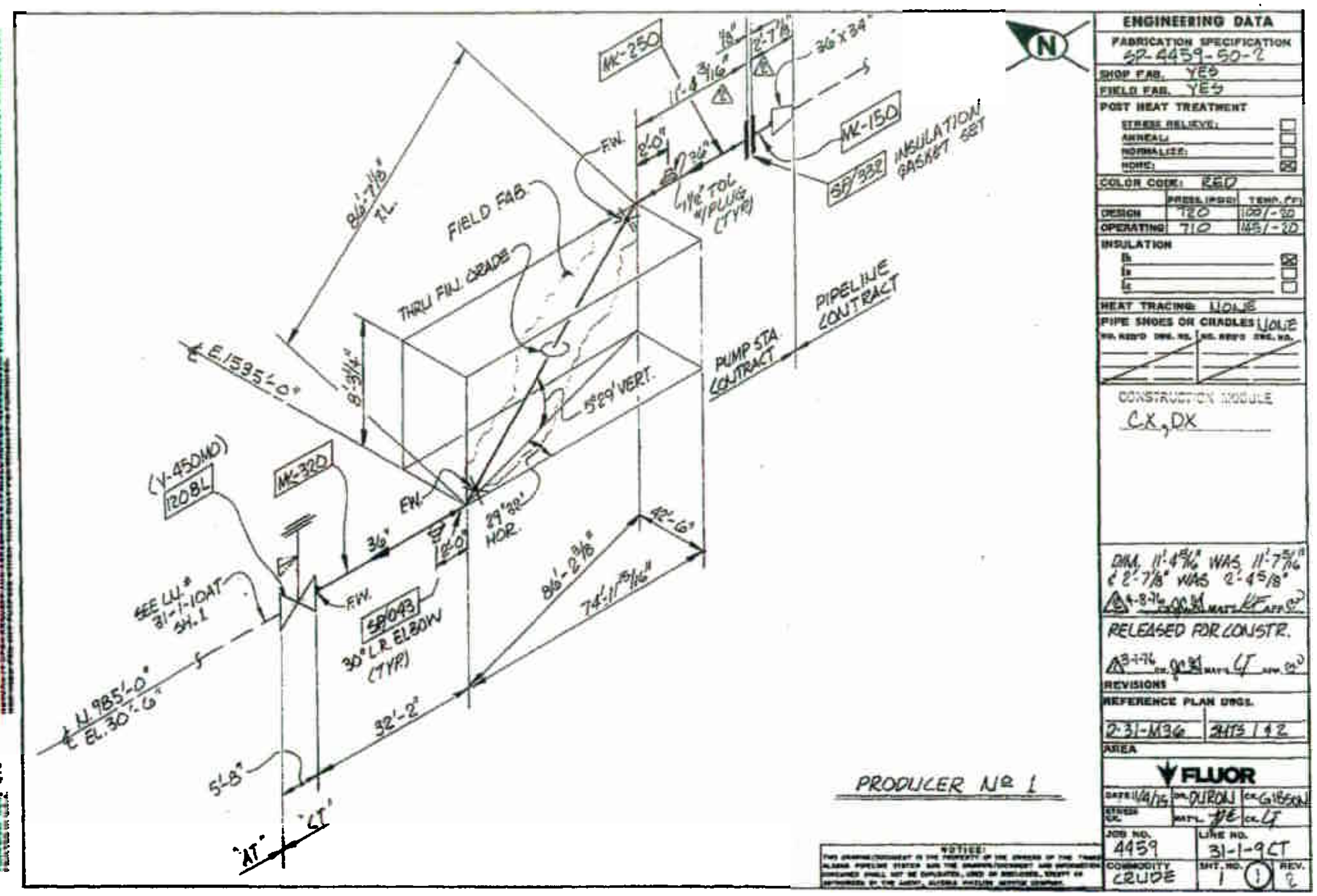
03/10/76 PIPING BILL OF MATERIAL

CONTRACT	LINE NO.	CLASS		SHT	REV
44590*	3101009	CT		01	01

KF 4/9/76

REV. NO.	ITEM CODE	QUANTITY	SIZE	DESCRIPTION
				SHOP FABRICATION MATERIAL
	MK-0150	1		
	MK-0250	1		
	MK-0320	1		
				FIELD FABRICATION MATERIAL
	0350603	85	30	PIPE .375 WALL DSAW SPEC STL API-5LX-X60
				FIELD ASSEMBLY MATERIAL
	0675656	32	1 5/8 X 13 3/4	STUD BOLT CHROME-MOLY A320 GRADE L7
	0822332	1	36	SP-332 INS GASKET SET 300# API
	311208L	1	30	
				FIELD SCRD.-S.W. MATERIAL
	0490360	2	1 1/2	PLUG HEX HEAD SCRD STL A105-71-HT

DESIGN CHANGE ONLY
NO MAT'L CHANGE

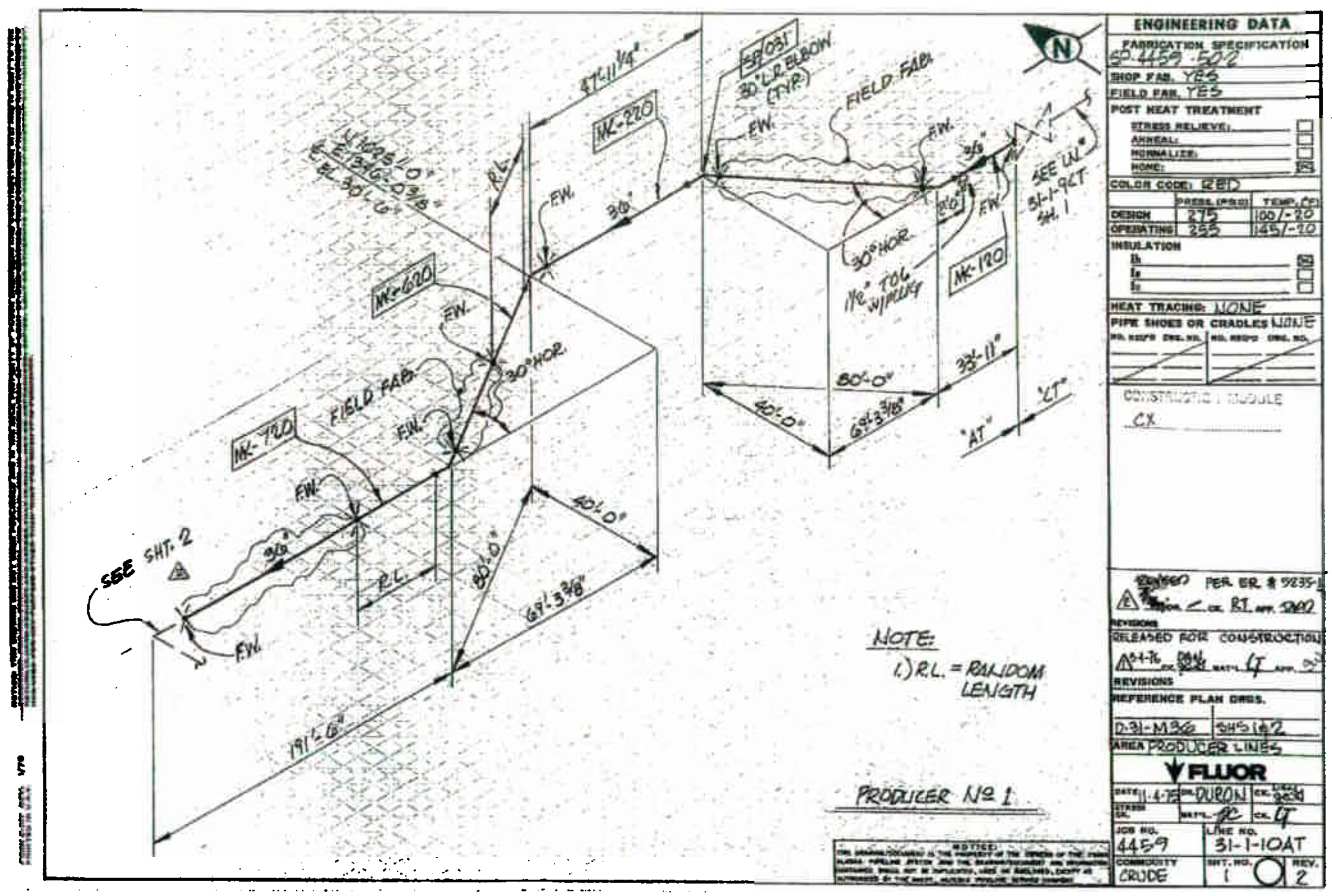


FLUOR

03/10/78 PIPING BILL OF MATERIAL

CONTRACT	LINE NO.	CLASS		SHT	REV
445984	3101010	AT		01	02

REV. NO.	ITEM CODE	QUANTITY	SIZE	DESCRIPTION
				SHOP FABRICATION MATERIAL
	MK-0120	1		
	MK-0220	1		
	MK-0020	1		
	MK-0720	1		
				FIELD FABRICATION MATERIAL
	0358600	261	36	PIPE .375 WALL DSAW SPEC STL API-5LX-X60
				FIELD SCRD.-S.W. MATERIAL
	0490368	1	1 1/2	PLUG HEX HEAD SCRD STL A105-71-HT



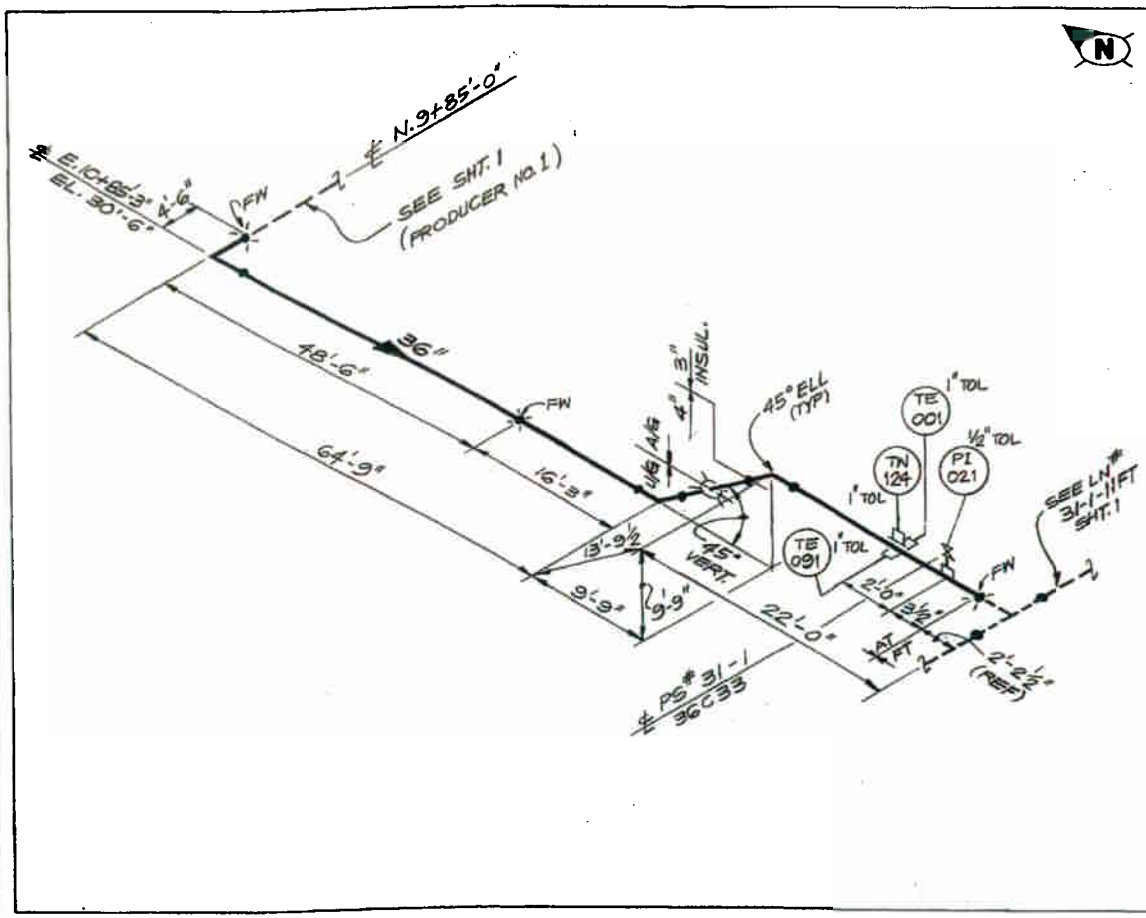
NOPV Response CPF 5-2008-5002
Exhibit 3
Page 2 of 5

Alyeska pipeline

BILL OF MATERIAL

LINE No.	CLASS		SHT	REV.
31-1-10	AT		2	1

REV.	ITEM CODE	QUAN.	SIZE	DESCRIPTION
	0362831	64 LF	36"	PIPE .375 DSAW SPEC STL API-5L-X60 C&W (U/G)
	0358600	23 LF	36"	— " — (ABOVEGROUND)
	0384702	1	36"	ELL 90 DEG LR STD WT STL LTEMP A420 WPL6-W
	0384706	2	36"	ELL 45 DEG STD WT STL LTEMP A420 WPL6-W
	0516649	3	1"	THREDOLET 3000# STL LTEMP A350 LF2
	— " —	1	1/2"	— " —
	0012951	1	1/2"	GATE 800# SCRD LOTEMP STL 316SS TRIM
	0541135	1	1/2"x3"	NIPPLE XS STL LTEMP A333-6 TBE



ENGINEERING DATA
FABRICATION SPECIFICATION SP-4459-50-2

SHOP FAB. ☒ FIELD FAB. ☒

	PRESS. (PSIG)	TEMP. (°F)
DESIGN	275	100/-20
OPERATING	255	145/-20

INSULATION: th = 2 ☒ ☐ ☐

HEAT TRACING: NONE

REMARKS:

REVISIONS

△ __ DR. __ CK. __ APP. __

△ __ DR. __ CK. __ APP. __

△ __ DR. __ CK. __ APP. __

△ INITIAL ISSUE PER ER# 5235-1 07-28-93 DR. RG CK. RT APP. CKO

M.F.D.: D-31-M71/M271

REF. DWGS.: D-31-M36 SHT. 1; D-31-M14 SHT. 2

AREA: PS#1-INCOMING GAS/PRODCR.

Alyeska pipeline

DATE: 07-28-93	DR.: RG	CK.: RT
APP.:	APP.:	APP.: CKO

LINE No.: 31-1-10AT

COMMODITY: CRUDE	SHT. No.: 2 (2)	REV.: 1

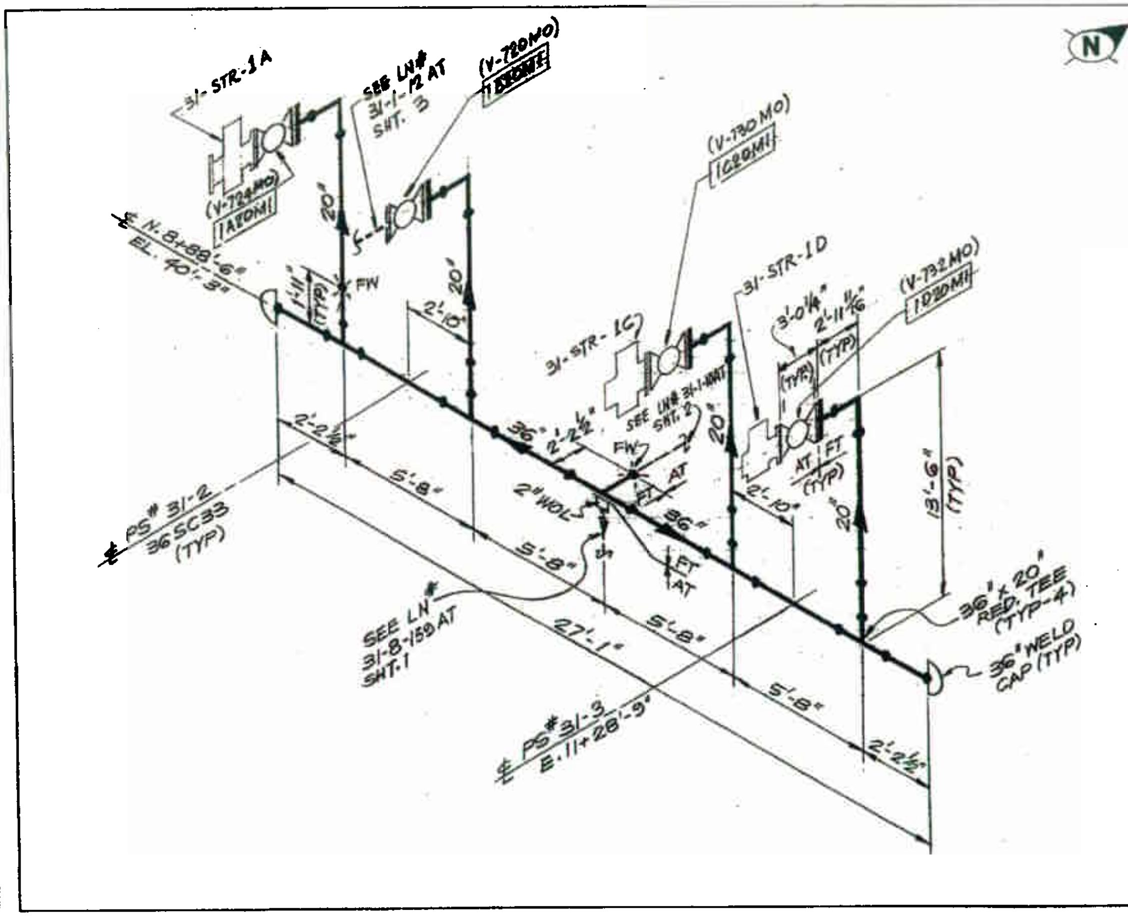
Title: D-31-1-10AT02R01 (BCAM)

Alyeska pipeline

BILL OF MATERIAL

LINE No.	CLASS		SHT	REV
31-1-11	FT		1	2

REV.	ITEM CODE	QUAN.	SIZE	DESCRIPTION
	0358610	10 LF	36"	PIPE .900 WALL DSAW SPEC STL API-5L-X60
	0358547	37 LF	20"	PIPE XS SMLS STL LOTEMP A333-6
	0394872	4	36x20	TEE, RED XS STL LOTEMP A860 WPHY-60
	— " —	1	36"	TEE XS STL LOTEMP A860 WPHY-60
	0394875	2	36"	DISH HEAD XS STL LOTEMP A860 WPHY-60
	0392626	4	20"	ELL 90 DEG LR XS STL LOTEMP A420 WPL6
	0557888	4	20"	FLG WN 150# RF STL LOTEMP LF2 STD. BORE
	0505172		2"	WELDOLET STD X XS STL LOTEMP A350 LF2
	0302422	4	20"	BALL 150# RF LOTEMP, 60 FULL PORT IAG
	0671486	8	20"	GASKET 150# 304 SS SP/WND FLEX I/RNG
	0675656	160	1 1/8x6 1/2	STUD BOLT CHROME MOLY A320 GR L7



ENGINEERING DATA

FABRICATION SPECIFICATION SP-4459-50-2

SHOP FAB. ☐ FIELD FAB. ☐

	PRESS. (PSIG)	TEMP. (°F)
DESIGN	275	100/-20
OPERATING	255	145/-20

INSULATION: Bi - 2 ☒ / Ir ☐ / Ic ☐

HEAT TRACING: NONE

REMARKS:

△ DR. __ CK. __ APP. __

△ DR. __ CK. __ APP. __

△ DR. __ CK. __ APP. __

AS-BUILT PER ERA #3283-1 DR. RJ CK. RT APP. CKO

REVISIONS

M.F.D.: D-31-M71 / M271

REF. DWGS.: D-31-M14 SHT. 2 & 4

AREA: PS#1 - METER BLDG.

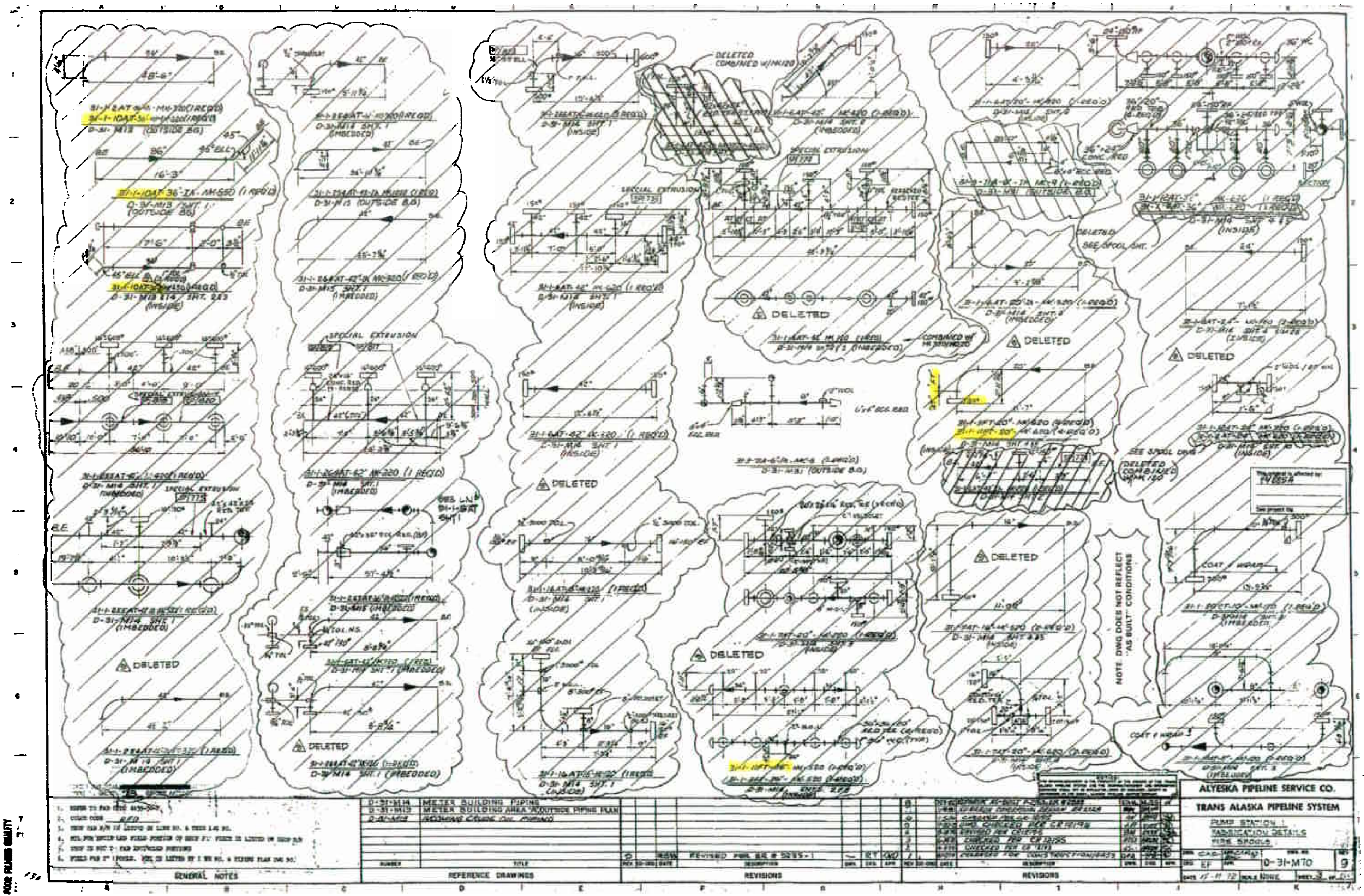
Alyeska pipeline

DATE: 07-27-93 | DR.: [illegible] | CK.: RT | APP.: | APP.: | APP.: [illegible]

LINE No.: 31-1-11 FT

COMMODITY: CRUDE | SHT. No.: 1 | 1 | REV. 2

Title: G-31-1-11FT001/02 (SCAN)


ALYESKA PIPELINE SERVICE CO.
TRANS ALASKA PIPELINE SYSTEM
PUMP STATION 1
FABRICATION DETAILS
PIPE SPOOLS
D-31-M70
NOTE: DWG DOES NOT REFLECT "AS BUILT" CONDITIONS
DELETED
GENERAL NOTES
REFERENCE DRAWINGS
REVISIONS
METER BUILDING PIPING
METER BUILDING AREA & OUTSIDE PIPING PLAN
SPECIAL EXTRUSION

3.1.3 Table 1C

Table 1C - AT Line Class
Pipe, Fitting, and Flange Schedule

		MAOP = 285 Psig (at 0.72 SMYS)							
		Pipe			Fittings		Flanges		
NPS	O.D.	W.T.	SMYS	W.P. @ .72% SMYS	Weight (End)	SMYS	Weight (End)	Standard/Class	SMYS
1-1/2	1.900	.200	35000		3000# SW	36000	3000# SW	B16.5, 150#	36000
[redacted]									
3	3.500	.216	35000		STD	35000	STD	B16.5, 150#	36000
[redacted]									
6	6.625	.280	35000	2130	STD	35000	STD	B16.5, 150#	36000
[redacted]									
10	10.750	.365	35000	1710	STD	35000	STD	B16.5, 150#	36000
[redacted]									
14	14	.375	35000	1350	STD	35000	STD	B16.5, 150#	36000
[redacted]									
18	18	.375	35000	1050	STD	35000	STD	B16.5, 150#	36000
[redacted]									
24	24	.375	60000	1350	STD	35000	STD	B16.5, 150#	36000
[redacted]									
30	30	.375	60000	1080	STD	35000	STD	B16.47, Series B, 150#	60000
[redacted]									
42	42	.438	60000	901	.438	35000	.438	B16.47, Series B, 150#	60000
[redacted]									

1) Pipe in conformance to specification P-100 (NPS 1-1/2 to NPS 20) or specification P-110 (NPS 24 to NPS 48).
2) Fittings and flanges in conformance to specification P-120 (NPS 1-1/2 to NPS 48).
3) A higher MAOP may be used for 285 psig service where quantity does not economically justify purchase of a lower grade or wall thickness.
4) Exceeds minimum design requirements of ASME B31.4, Table 402.3.1(a).

3.1.1 Table 1A

Table 1A - FT Line Class
Pipe, Fitting, and Flange Schedule

		MAOP = 1180 Psig (at 0.72 SMYS)							
		Pipe[1]			Fittings[2]		Flanges[2]		
NPS	O.D.	W.T.	SMYS	W.P. @ .72% SMYS	Weight (End)	SMYS	Weight (End)	Standard/Class	SMYS
1-1/2	1.900	.200	35000		3000# SW	36000	3000# SW	B16.5, 600#	36000
[redacted]									
3	3.500	.216	35000		STD	35000	STD	B16.5, 600#	36000
[redacted]									
6	6.625	.280	35000	2130	STD	35000	STD	B16.5, 600#	36000
[redacted]									
10	10.750	.365	35000	1710	STD	35000	STD	B16.5, 600#	36000
[redacted]									
14	14	.375	35000	1350	STD	35000	STD	B16.5, 600#	36000
[redacted]									
18	18	.500	35000	1400	XS	35000	XS	B16.5, 600#	36000
[redacted]									
24	24	.375	60000	1350	STD	60000	STD	B16.47, Series A, 600#	60000
[redacted]									
30	30	.500	60000	1440	.500	60000	.500	B16.47, Series A, 600#	60000
[redacted]									
42	42	.562	65000	1252	.625	60000	Note 4	B16.47, TAPS Series A, 600#	60000
[redacted]									
48	48	.562	70000	1180	.688	60000	Note 4	B16.47, TAPS Series A, 600#	60000

1) Pipe in conformance to specification P-100 (NPS 1-1/2 to NPS 20) or specification P-110 (NPS 24 to NPS 48).
2) Fittings and flanges in conformance to specification P-120 (NPS 1-1/2 to NPS 48).
3) Exceeds minimum design requirements of ASME B31.4, Table 402.3.1(a).
4) Flange ID bore and bevel thickness are specified in Dwg. No. B-10-M230 (NPS 42) or B-10-M232 (NPS 48).

PROBABLE VIOLATION 4:
Overpressure Safety Devices and Overfill Protection Systems

PHMSA POSITION

Pertinent Regulation:
49 CFR §195.428 Overpressure Safety Devices and Overfill Protection Systems

> (a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7-1/2 months, but at least twice each calendar year, 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, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

Findings*:*
Alyeska's Kuparuk piping has a MOP of 1180 psig, while the Kuparuk pipeline system has a MOP of 1440 psig. Alyeska has installed a pressure transmitter (31-PT-013A) to protect the 1180 psig piping from overpressure. Alyeska's "OM-1, Procedural Manual for Operations, Maintenance and Emergencies," Section 7 does not address this pressure transmitter or list it as required for testing. Alyeska presented records at Pump Station 1 of performing calibration of this pressure transmitter, indicating that transmitters were calibrated annually.

Evidence:
1. In Alyeska's response to request for specific information, it states that Alyeska's incoming Kuparuk pipe has a MOP 1180 psig, while Kuparuk's incoming pipeline has an MOP of 1415 psig.
2. Pressure transmitter calibration sheets for 2005, 2006.
3. OM-1 Section 7, does not list 31-PT-13A as a pressure-controlling device.

Proposed Compliance Order:
In regard to Item Number 4 of the Notice pertaining to the pressure transmitter (31-PT-013A) on the Kuparuk pipeline incoming line to Alyeska. This pressure transmitter shall be maintained as DOT critical safety devices.

Alyeska Pipeline Service Company shall revise "OM-1, Procedural Manual for Operations, Maintenance and Emergencies," Section 7, to indicate that these pressure shutdown switches are DOT critical safety devices. Alyeska shall also conduct annual tests of these pressure shutdown switches and shall maintain and make available to PHMSA the records of such testing.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) does not contest this finding. In May 2008, Alyeska updated OM-1 to include 31-PT-013A as a DOT critical safety device and updated the model work order package to ensure that it is maintained to DOT requirements. Alyeska respectfully requests that PHMSA withdraw the proposed compliance order.

Discussion:
Alyeska agrees that the pressure transmitter 31-PT-013A protects the Kuparuk connection piping from overpressure. As the records indicate, Alyeska has been maintaining 31-PT-013A as an overpressure safety device, which includes annual calibration testing (see Exhibit 6).

Alyeska acknowledges that OM-1, Section 7, *Overpressure Safety Devices, Overfill Protection Systems, Valves and Breakout Tanks*, did not address 31-PT-013A as an overpressure safety device. Alyeska has already updated OM-1, Section 7.1, *General Equipment Description of Overpressure Safety Devices and Method of Compliance*, to include reference to 31-PT-013A as the device that provides relief protection on the Kuparuk connection piping (see Exhibit 7). Further, to ensure that the calibration tests are conducted annually as required by §195.428, Alyeska has already updated the model Work Order package for the required Preventive Maintenance (see Exhibit 8).

With regard to Finding 4, Alyeska respectfully requests that PHMSA withdraw the finding and the proposed compliance order as the pressure transmitter is currently maintained as a DOT critical safety device and OM-1 has been updated.

SUPPORTING DOCUMENTATION

Exhibit 6 -- Calibration certificate for 31-PIT-013A
Exhibit 7 -- OM-1, Section 7.1, *General Equipment Description of Overpressure Safety Devices and Method of Compliance*, Ed. 2, Rev. 15, May 21, 2008
Exhibit 8 -- Model work order #38009351, K10 Kuparuk Pressure Protection, May 14, 2008

Alyeska Pipeline Gas Metering
Static Pressure Calibration Certificate

Tag Number: 31-PIT-013A **Work Order #:** 37018811-01

Location/Service: Kuparuk Inlet Header Pressure

End Device: Daniels 2233 Flow Computers

Pressure Range: 0 - 500 PSIG

	Actuation SP	As-Found	As-Left
Increasing	↑ 400 psi	400	N/A
Decreasing	N/A	—	—

Alarms / Functions	Yes	No
At Kuparuk - Hi ↑350 ~~& Hi-Hi ↑400 psi~~	✓	
Hi-Hi @ 400 PSIG	✓	
	↓	

Range %	Data PSIG	Certified	As-Found	End Device PSIG	As-Left
0	0	Ø	Ø.Ø	-5 » 5	SAME
25	125.0	125.0	124.4	120 » 130	↓
50	250.0	250.0	249.2	245 » 255	
75	375.0	375.0	374.1	370 » 380	
100	500.0	500.0	499.0	495 » 505	

Test Equipment Used and Certification Due Date:

BEAMEX - 206673 - 13JUL08 / EPM - 206954 - 13JUL08

Calibration Performed By: D MUSSELMAN

Witnessed or Assisted By: R WEINRICK

Date: 9 OCT 2007

Comments: NO ADJUSTMENT NECESSARY

Section 7 Overpressure Safety Devices, Overfill Protection Systems, Valves and Break-Out Tanks

DOT/OPS Requirement

49 CFR 195.428, Overpressure Safety Devices and Overfill Protection Systems

a. Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, **or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year,** [the bold portion of this regulation does not apply to Alyeska because North Slope Crude is not a "highly volatile liquid"] 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, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

b. Not Applicable to Alyeska.

c. Not Applicable to Alyeska.

d. After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

7.1 General Equipment Description of Overpressure Safety Devices and Method of Compliance

In all of the pump stations, piping pressure relief systems have been designed to keep surge pressures from exceeding 110 percent of the pipe internal design pressure. Facility equipment and piping are normally protected during operation by the mainline relief system. Under certain conditions, low-pressure piping remains open to an atmospheric system (e.g. relief tank or sump), or is designed to operate above any source of pressure in the system.

Alyeska annually inspects and tests relief valves and control devices for mainline piping to confirm operability and mechanical condition. (See Section 7.1.1.4 for a description of the function test devices.) Per regulation, all inspection and testing of overpressure safety devices must be completed at intervals not exceeding 15 months, but at least once each calendar year. This is accomplished as described in Section 7.1.1.4.

Some vessels and piping are equipped with thermal relief valves that will protect them from over-pressure in case of thermal expansion when the system is blocked in. These valves are regulated by the annual inspection requirement of *ASME B31.4,* and will be tested in accordance with this code.

Relief protection is provided on the residuum return line at the North Pole Metering Facility. In the event of overpressure, the residuum is diverted back to the refinery crude supply line.

Backpressure control valves are provided on the main crude line entering the terminal to address hydraulic conditions where the oil flows off Thompson Pass.

Relief protection is provided on the Kuparuk line coming into PS01. A 400 psi signal from 31-PT-013A will alarm at Kuparuk and stop crude flow from Kuparuk, Milne Point, and Alpine. A 500 psi pressure on 31-PSH-013C will alarm at Kuparuk and close 31-MOV-320BL at PS01.

7.1.1 Relief Valves for Mainline Piping

The mainline pressure relief system protects the mainline, pump station, and terminal piping from over-pressure. Relief valves are located on the suction and discharge sides of the pump stations and on incoming crude piping at the Terminal. See Table 7.1. Pressure relief for each pump station is provided by connecting the suction and discharge relief valve piping manifolds to the crude relief tanks. Connection to the tank varies for each pump station.

Table 7.1 Mainline Relief Valves Requiring Annual Inspection and Testing (Reference 49 CFR 195.428(a))

Location	Equipment Description	Tag Number
PS01	Pressure Indicating Control Valve - Suction Relief (3)	31-PICV-104A/B/C
PS01	Pressure Indicating Control Valve - Discharge Relief (2)	31-PICV-105A/B
PS02 *	Pressure Indicating Control Valve - Suction Relief (3)	32-PICV-204/C
PS02	Pressure Indicating Control Valve - Discharge Relief (2)	32-PICV-205A/B
PS03	Pressure Indicating Control Valve - Suction Relief (3)	33-PICV-304A/B/C
PS03	Pressure Indicating Control Valve - Discharge Relief (3)	33-PICV-305A/B/C
PS04	Pressure Indicating Control Valve - Suction Relief (3)	34-PICV-404 A, B, C
PS05	Pressure Indicating Control Valve - Suction Relief (3)	35-PICV-504 A, B, C
PS05	Pressure Indicating Control Valve - Discharge Relief (1)	35-PICV-505B
PS06 *	Pressure Indicating Control Valve - Suction Relief (2)	36-PICV-604A/B
PS06 *	Pressure Indicating Control Valve - Discharge Relief (2)	36-PICV-605A/B
PS07	Pressure Indicating Control Valve - Suction Relief (3)	37-PICV-704A/B/C
PS07	Pressure Indicating Control Valve - Discharge Relief (2)	37-PICV-705A/B
NPM	Pressure Control Valve - Residuum	43-PCV-505
PS08 *	Pressure Indicating Control Valve - Discharge Relief (2)	38-PICV-805A/B
PS09	Pressure Indicating Control Valve - Suction Relief (3)	39-PICV-904A/B/C
PS09	Pressure Indicating Control Valve - Discharge Relief (2)	39-PICV-905A/B
PS10 *	Pressure Indicating Control Valve - Suction Relief (3)	40-PICV-1004A
PS10 *	Pressure Indicating Control Valve - Discharge Relief (2)	40-PICV-1005A/B
PS12 *	Pressure Indicating Control Valve - Suction Relief (3)	42-PICV-1204A/B/C
PS12 *	Pressure Indicating Control Valve - Discharge Relief (2)	42-PICV-1205A/B
VMT	Pressure Indicating Control Valve - Incoming Relief (1)	58-PSV-004

NOPV Response CPF 5-2008-5002
Exhibit 7
Page 2 of 2

Facility: P/L PIPELINE/ROW WORK MGMT. UNITS
Unit : PS01 Project :
Ref Type: Ref No.:
W/O Type: MO Group : W/O Dspln :
Planner : U183350 ATTLA C
W/O Title : K10,KUPARUK PRESSURE PROTECTION
W/O Task Title: K10,KUPARUK PRESSURE PROTECTION
Written To : SYSTEM TAG - METER
Task Dspln : Task Pri: 03 Need Date:

Work Order Package

38009351 01

Rpt : TIPMC11
Date: 05/14/08

Alyeska pipeline

APPROVED
Page: 1

Work Order Task Written To

Facility : P/L
Unit : PS01
Op Sys :
Division : 31
Area : FACILITY
Sys/Cls: MTR
Equipment : SYST SYS-METER
Component:
Work Item :
Eqt. List:
Ops Review Reqd:
Equip. Tag: 31-SYS-METER
Alt:
UTC :
Tbl/Brkdwn: (Past 12 mo)
Catalog ID:
Job Type : PM UCR:
Client/Act:
Location : PS01
Cost Centr: 811011
Activity :
User Def:
Percentage: 100.000
Acct No. : GL 400 003

Work Order Task Instructions

NOTE: CHANGES TO, THIS PM MUST BE REVIEWED AND APPROVED BY THE OIL MEASUREMENTS TEAM.
.
NOTE: THIS PM IS MANDATORY FOR REGULATORY COMPLIANCE WITH THE REQUIREMENTS OF 49 CFR 195.428.
.
NOTE: THIS WORK MUST BE PERFORMED OR SUPERVISED BY PERSONNEL QUALIFIED ON PC-CEI/002 per 49 CFR 195.428
.
NO 3RD PARTY INSPECTION REQUIRED.
.
PARTS/MATERIALS/TOOLS:
-CERTIFIED MULTIMETER
- CERTIFIED BEAMEX PC105
.
SPECIAL INSTRUCTIONS:
-A 400 PSI SIGNAL FROM 31-PT-013A WILL ALARM AT KUPARUK AND STOP CRUDE FLOW FROM BOTH KUPARUIK AND MILNE POINT.
-A 500 PSI PRESSURE ON 31-PSH-013C WILL ALARM AT KUPARUK AND CLOSE 31-MOV-320BL AT PS01. THERE IS ALSO AN ALARM ON THE KUPARUK METER PANEL AT PS01.
-NOTIFY OCC AND KUPARUK PRIOR TO CALIBRATING THESE INTRUMENTS SO THE NECESSARY BYPASSES CAN BE INSTITUTED.
-COORDINATE WITH OPERATIONS TO STOP 31-MOV-320BL TRAVEL AS

Facility: P/L PIPELINE/ROW WORK MGMT. UNITS
Unit : PS01 Project :
Ref Type: Ref No.:
W/O Type: MO Group : W/O Dspln :
Planner : U183350 ATTLA C
W/O Title : K10,KUPARUK PRESSURE PROTECTION
W/O Task Title: K10,KUPARUK PRESSURE PROTECTION
Written To : SYSTEM TAG - METER
Task Dspln : Task Pri: 03 Need Date:

Work Order Package

38009351 01

Rpt : TIPMC11
Date: 05/14/08

APPROVED
Page: 2

Work Order Task Instructions

SOON AS IT'S NOTICED AND REOPEN THE VALVE AFTER PRESSURE HAS BEEN REMOVED FROM 31-PSH-013C.

.

START OF TASK:

.

SCOPE: ANNUAL INSTRUMENT CALIBRATION OF KUPARUK OVER PRESSURE PROTECTION TRANSMITTER AND PRESSURE SWITCH

.

001.) CALIBRATE THE FOLLOWING AS PER MANUFACTURER'S SPECS OR PER OIL MEASUREMENTS MANUAL OM-41:

.

31-PT-013A* INLET HEADER PRESSURE TRANSMITTER
VERIFY KUPARUK GETS SOFTWARE ALARM AT 400 PSI.
31-PSH-013C* INLET HEADER HIGH PRESSURE SWITCH
*VERIFY THAT 31-MOV-320BL OPERATES AT 500 PSI
AND THAT KUPARUK AND PS01 GETS ALARM

.

002: APPLY CALIBRATION STICKERS TO DEVICES

.

003.) THE FOLLOWING LIST INCLUDES ALL DOCUMENTS REQUIRED FOR COMPLETION OF THIS TASK

.

OM-0001 OM-0006

.

END OF PROCEDURE

Task Requirements

FAC.	REG/REQ	VALUE	COMMENTS
P/L	49CFR195	428	OVERPRESSURE OF SAFETY DEVICES

QC Requirements/Comments

NO QC REQUIREMENTS FOR THE WORK ORDER TASK

Facility: P/L PIPELINE/ROW WORK MGMT. UNITS
Unit : PS01 Project :
Ref Type: Ref No.:
W/O Type: MO Group : W/O Dspln :
Planner : U183350 ATTLA C
W/O Title : K10,KUPARUK PRESSURE PROTECTION
W/O Task Title: K10,KUPARUK PRESSURE PROTECTION
Written To : SYSTEM TAG - METER
Task Dspln : Task Pri: 03 Need Date:

Work Order Package

38009351 01

Rpt : TIPMC11
Date: 05/14/08

Alyeska pipeline

APPROVED
Page: 3

References/Document Information

Type/Subtyp: PROC Number: OM-41 Sheet:
Title/Desc : OIL MEAUREMENTS MANUAL Image: N

Work Completion Signatures

Name/Badge	Function/Dept.	Date/Hours Worked

Completion Comments on Work Performed

COMMENTS:

***** E N D O F R E P O R T *****

PROBABLE VIOLATION 5:
Monitoring External Corrosion

PHMSA POSITION

Pertinent Regulation:

49 CFR §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.

(e) Corrective action. You must correct any identified deficiency in corrosion control as required by §195.401(b).

Findings:

An area (MP 12.2-13.2) of the pipeline was found to have inadequate cathodic protection (CP). These low CP readings were confirmed by Close Interval Surveys conducted in 2003, 2004, 2005 and 2006. This low CP area was further confirmed by 2002-2006 coupon readings. This section of the pipeline did not meet criteria set forth in section 195.571. This area of low CP levels was reported on a 2002 inspection (see PHMSA Final Order, CPF-2003-5002).

Evidence:

1. 2003-2006 CIS, Below -850 mil volt.
2. 2001-2006 Coupon survey, Below -850 mil volt and -100 mv shift.
3. Final Order CPF 5-2003-5002, page 3, Item 6, First allegation.

Proposed Civil Penalty:

The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that Alyeska be preliminarily assessed a civil penalty in the amount of $56,000.00.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:

Alyeska Pipeline Service Company (Alyeska) does not contest this finding.

Discussion:
Alyeska installed a wind generator at MP 12.5 in 2003. The wind generator suffered failures in early 2004 due to extreme arctic wind and icing conditions. Alyeska removed the unit for a complete overhaul and reinstalled the unit in June 2004. From June 2004 until February 2006, the unit operated intermittently and required various repairs. In February 2006, the unit was shut down to repair several connections between the power supply and anodes that failed due to frost jacking. The unit was re-energized in July 2006 but continued to operate intermittently. Alyeska decided to replace the existing wind generator with a more reliable wind/solar generator system. The new unit was designed in late 2006. Fabrication began in late 2006 and was completed in 2007. The unit was installed in September 2007 and has performed well since then as evidenced by the rectifier readings (see Exhibit 9).

SUPPORTING DOCUMENTATION

Exhibit 9 -- Bimonthly Rectifier Readings since September 2007

Wind/Solar CP System at MP 12.5
Bimonthly Rectifier Readings Since 9/2007

Reading Date	DC Volts	DC Amps	Surveyor	Comments
3/20/2008	5.35	7.4	A11257	BIMONTHLY READING
01/21/2008	4.97	7.3	A11257	BIMONTHLY READING
11/17/2007	4.55	7.9	A11257	BIMONTHLY READING
09/26/2007	5.25	9.55	A11778	BIMONTHLY READING

PROBABLE VIOLATION 6:
Monitoring External Corrosion

PHMSA POSITION

Pertinent Regulation:
49 CFR §195.573 What Must I do to Monitor External Corrosion Control?

(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	Check frequency
Rectifier	At least six times each calendar year, but with intervals not exceeding 2 1/2 months.
Reverse current switch	
Diode	
Interference bond whose failure would jeopardize structural protection	
Other interference bond	At least once each calendar year, but with intervals not exceeding 15 months.

(e) Corrective action. You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

Evidence:
1. Rectifier readings 2003-2007. When operational, the output should be in the range of 5 volts and 1 amp.
2. Final Order CPF 5-2003-5002, page 3, Item 6, First allegation.

Findings:
A rectifier powered by wind (31 EE 125) was installed in October 2003 at MP 12.5. Records indicated that the rectifier was only performing correctly on 11 occasions out of the 35 scheduled readings taken between October 2003 and July 2007.

Proposed Civil Penalty:
The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violation(s) and has recommended that Alyeska be preliminarily assessed a civil penalty in the amount of $56,000.00.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) does not contest this finding.

Discussion:
Alyeska installed a wind generator at MP 12.5 in 2003. The wind generator suffered failures in early 2004 due to extreme arctic wind and icing conditions. Alyeska removed the unit for a complete overhaul and reinstalled the unit in June 2004. From June 2004 until February 2006, the unit operated intermittently and required various repairs. In February 2006, the unit was shut down to repair several connections between the power supply and anodes that failed due to frost jacking. The unit was re-energized in July 2006 but continued to operate intermittently. Alyeska decided to replace the existing wind generator with a more reliable wind/solar generator system. The new unit was designed in late 2006. Fabrication began in late 2006 and was completed in 2007. The unit was installed in September 2007 and has performed well since then, as demonstrated by the rectifier readings (see Exhibit 10).

SUPPORTING DOCUMENTATION

Exhibit 10 -- Bimonthly Rectifier Readings since September 2007

Wind/Solar CP System at MP 12.5
Bimonthly Rectifier Readings Since 9/2007

Reading Date	DC Volts	DC Amps	Surveyor	Comments
3/20/2008	5.35	7.4	A11257	BIMONTHLY READING
01/21/2008	4.97	7.3	A11257	BIMONTHLY READING
11/17/2007	4.55	7.9	A11257	BIMONTHLY READING
09/26/2007	5.25	9.55	A11778	BIMONTHLY READING

PROBABLE VIOLATION 7:
Smoking or Open Flames

PHMSA POSITION

Pertinent Regulation:
49 CFR §195.438 Smoking or Open Flames

> Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

Findings:
During the inspection, "No Smoking" signs were missing or faded at the following valve locations: CKV 5, 8, 9, 10, 14, 16, 17, 18, 22, and MGV 5A and 10A.

Warning Item:
With respect to Item 7, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct this item. Be advised that failure to do so may result in Alyeska Pipeline Service Company being subject to additional enforcement action.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) does not contest this finding although Alyeska finds it inconsistent with §195.438. Alyeska has scheduled the installation of "No Smoking" signs at the locations listed above. Field Material Requisition #4571 has been generated to order the "no smoking" signs.

Discussion:
Alyeska prohibits smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors per §195.438.

This finding is not consistent with §195.438 as the finding addresses "No Smoking" signs around valve locations, not around pump stations and break out tank areas. However, Alyeska supports posting "No smoking" signs where appropriate and will review its policies and procedures to ensure the appropriate concerns are addressed. In addition, Alyeska will replace any faded or missing signs at the appropriate locations (see Exhibit 11).

SUPPORTING DOCUMENTATION

Exhibit 11 -- Field Material Requisition #4571

Field Material Requisition #4571

WO-Task #:		**Group:**	Fairbanks Maintenance Base		
WO Status:		**Facility:**	VHF	**Request Date:**	5/19/2008 8:24:40 AM
Title:		**Tag/Equip #:**		**Approved Date:**	5/19/2008 9:06:02 AM
Project #:		**Job Location / Deliver To:**		**Status Date:**	5/19/2008 9:06:02 AM
Cost String:	8100	Signs for CKV PS#1 , PS#3, PS#5		**Status:**	Ordered

Processed By: Taylor, Brian W.   **Associated Material Coordinators:** Stevens, William(Eddie)   **Estimated Cost:**

Requester:	**Ext:**	**Engineer:**	**Ext:**	**AAG Approval:**	**Ext:**
Taylor, Brian W.	5344			Bell, Kathleen F.	(907) 450-7914
Signature:	**Date:**	**Signature:**	**Date:**	**Signature:**	**Date:**

Line #	Status	Qty / Unit of Purchase	Passport Catalog ID / Part No. / Manufacturer	Item Description	Estimated Unit Price / Site Need Date / Est. Delivery	MR/CC Vendor / To Be Returned / Traceability Type	Certs and/or Tests Req'd?	Inspection Req'd?	Substitutions OK?	Cost Coding Notes / Mark For / Web Address	Received Warehouse / Received Field
1	Ordered	38	Warning signs of AK	Danger no smoking in this area 30" X 30"	5/30/2008	Warning lites of AK ☐	☐	☐	☐	8100	0 / 0

Special Instruction/Markings/Comments:

HOT!!!HOT!!! 1 week out per Warning lites of Alaska

NOPV Response CPF 5-2008-5002
Exhibit 11
Page 1 of 1

PROBABLE VIOLATION 8:
Mitigation of Internal Corrosion

PHMSA POSITION

Pertinent Regulation:
49 CFR §195.579 What must I do 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.

Findings:
Alyeska has removed piping associated with the Endicott meter run. Alyeska did not provide an inspection report for this pipe for internal corrosion.

Warning Item:
With respect to Item 8, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct this item. Be advised that failure to do so may result in Alyeska Pipeline Service Company being subject to additional enforcement action.

ALYESKA PIPELINE SERVICE COMPANY'S RESPONSE

Summary:
Alyeska Pipeline Service Company (Alyeska) does not contest this finding. Alyeska acknowledges that the piping removed from the Endicott meter run should have been inspected for internal corrosion. In April 2008, Alyeska updated MP-166-3.03, *Facility Corrosion Integrity Monitoring*, and Master Specification B-511, *Pump Station and Terminal Pipe Investigation Specification*, to specifically require corrosion inspection of any removed section of pipe.

Discussion:
Alyeska acknowledges that it did not provide an inspection report for the Endicott meter run piping that was removed in 2007. The pipe is approximately two feet of 2 inch diameter drain pipe, containing two 45 degree elbows. Alyeska scheduled the replacement due to a 2006 UT grid inspection that identified internal corrosion on that section. At removal, either a pipeline investigation report (PIR) or a corrosion investigation report (CIR) should have been completed.

Alyeska has updated its procedures to ensure that all removed pipe is inspected as required by §195.579. MP-166-3.03, *Facility Corrosion Integrity Monitoring*, has a new section 5.2.4, *Piping Removed from Service*, which requires visual inspection and documentation on a CIR (see Exhibit 12). Master Specification B-511, *Pump Station and Terminal Pipe Investigation Specification,* includes a new section 3.5.4, *Piping Recommended or Required for Removal from Service,* which required visual inspection and documentation on a CIR (see Exhibit 13). Additionally, MR-48, *Trans-Alaska Pipeline Maintenance and Repair Manual*, includes requirements for inspection of any removed pipe and completion of a PIR (see Exhibit 14).

With regard to Finding 8, Alyeska has provided updated procedures to ensure that internal inspection will be conducted when any pipe is removed.

SUPPORTING DOCUMENTATION

Exhibit 12 -- MP-166-3.03, *Facility Corrosion Integrity Monitoring*, Section 5.2.4, *Piping Removed from Service*, Rev. 9, April 25, 2008

Exhibit 13 -- Master Specification B-511, *Pump Station and Terminal Pipe Investigation Specification*, Section 3.5.4, *Piping Recommended or Required for Removal from Service*, Rev. 11, April 22, 2008

Exhibit 14 -- MR-48, *Trans-Alaska Pipeline Maintenance and Repair Manual,* Section 2.6.1.3, *Pipe Inspection*, and Section 17.4.2., *Pipe Inspections*

5.2 Analysis of Data

5.2.1 Data Storage

The data obtained from the inspections performed by the PIT Program are entered and archived into the Alyeska Electronic Data Management (EDM) system. The inspection data obtained from individual inspection grid locations as well as atmospheric corrosion evaluations, once analyzed, is loaded into the EDM system where it can be retrieved for future use for system analysis, to aid in determining future inspections, to identify the system health of a piping segment at a facility, or to trend corrosion rates of a piping segment.

5.2.2 Procedure to Determine Fitness for Service

Final acceptable analysis shall be performed per Master Specification *B-511*. More conservative interim analysis may be performed for screening purposes to expedite the inspection and analysis process. Two acceptable procedures for conservative interim analysis include using:

1. the ASME B-31G method; and,
2. the ASME B-31G method assuming maximum longitudinal extent of corrosion such that Part 4.2(b) factor A is greater than 4.0.

5.2.3 Corrosion Control Improvements

Alyeska's policy for corrosion control planning for oil and vapor systems allows for a prioritized or risk-based approach to corrosion control. Alyeska's Risk Assessment Procedure is defined in *AMS-017-01*. This method requires periodic excavation inspections and/or CP monitoring of buried piping. Corrosion control for the purpose of safety and reducing risk of oil discharge may include pipe replacement, pipe remode (moving belowground pipe to aboveground mode), removing piping systems from service, and installing or upgrading cathodic protection systems.

5.2.4 Piping Removed From Service

When it is determined to have piping removed from service due to the results of the corrosion investigations, a visual inspection will be performed on the affected piping, any associated fittings and the adjacent piping both upstream and downstream. Once the removed materials have been inspected and documented, they can be discarded. A person competent and experienced in corrosion engineering in Alyeska Integrity Management Engineering and/or a person directly associated with the PIT Program such as the Program Corrosion Field Engineer (CFE) or Program Support Engineer shall perform the required inspections.

The results of the inspections will be documented on a Corrosion Investigation Report (CIR) and submitted to the Alyeska Integrity Management Engineering PIT Program Support Engineer. The hard copy of the CIR will be placed in the Integrity Management Engineering files and the PIT Program data base will be updated to reflect the removal of the piping and installation of new piping. As necessary (if existing inspection sites/grids affected); an electronic CIR will be completed in EDM identifying the results and piping replacement information. As a result of any newly installed piping, a baseline inspection will be scheduled under the PIT Program to take place not more than one year after the installation or as soon as practical.

6.0 Reporting

The Integrity Management Engineer summarizes the results of monitoring activities and proposes recommendations to the assets in the Pipeline and Terminal Facilities Integrity Management Annual Report in accordance with *MP-166-1.00*, ***Integrity Management Programs Process***.

7.0 Records

UT/Pit Gauge data (facility)	All records generated as a result of this document will be retained in accordance with *CW-200*, *Records Retention Schedule*.
Notification of allowable pressure below MOP, non-mainline	
CIR (Corrosion Investigation Report)	
Copies of UT Field File/ Calibration Sheets	

All of the above records are generated as a result of specifications *B-511*.

8.0 Revision History

Approved by Tom Webb, Integrity Engineering Manager		
Revision	**Date**	**Revision Summary**
9	04/25/08	• Complete Review. • Section 4: Revised heading to read Accountable Resources to more closely align with the Accountability Leadership Initiative. • Addition of Section 5.1.4: Atmospheric Corrosion Control. • Addition of Section 5.2.3: Corrosion Control Improvements. • Addition of Section 5.2.4: Piping Removed From Service • Section 5.1.6: Revision • Verified and updated references throughout document.
8	01/31/08	• Revised title and Unique ID of reference to *AMS-017* (now *AMS-017-01*).

Master Specification B-511

Pump Station and Terminal Pipe Investigation Specification

Rev. No.	Date	Document Owner	Document SPOC	SME
11	04/22/08	T. Webb	T. Balowski	T. Balowski
10	04/21/06	J. K. Miller	T. Balowski	R. Annett
9	09/15/05	P.G. McDevitt	T. Balowski	R. Annett
8	02/15/05	P.G. McDevitt	T. Balowski	R. Annett
7	12/31/01	J.W. Roddick	L.A. Disbrow	A. Williams
6	03/06/00	J.W. Roddick	L.A. Disbrow	B.L. Flanders
5	05/14/99	J.W. Roddick	L.A. Disbrow	B.L. Flanders
4	06/18/96	P.K. Brashears	K.R Hastain	W.R. Mott
3	05/12/95	P.K. Brashears		K.R Hastain
2	04/20/94	W.J.M. Steel		K.R Hastain
1	05/05/93	W.J.M. Steel		K.R. Hastain
0	04/09/92	G. Irvine		K.R. Hastain

Revision History

Master Specification B-511		
Approved by Tom Webb, Integrity Engineering Manager		
Rev. No.	**Date**	**Comments**
11	04/22/08	Complete Review. References verified and updated. Minor revisions throughout referencing atmospheric corrosion control. Major revision of Section 3.4.6. Addition of Section 3.5.4. Major revision of Section 3.5.5.
10	04/21/06	Merge Master Specification *B-513* into *B-511*. Updated to reflect revision of DOT 195 Subpart H. Updated to reflect IM Engineering function.
9	09/15/05	Replaced *QA-36* references with *AMS-031*. Updated to correct document title for *NDT-TP-708*.
8	02/15/05	Minor Change to Section 3.1.2. Updated formatting. Updated references throughout.
7	12/31/01	Reformatted document to current Alyeska standards. Removed all references to Integrity level ratings.
6	03/06/00	Specification was revised as part of periodic review. Attachment M-004 was removed and incorporated into APSC *IP-231*.
5	05/14/99	Specification was revised as part of periodic review. Changes reflect revisions to forms, and the revision of M-004 to improve the data collection process.
4	06/18/96	N/A
3	05/12/95	N/A
2	04/20/94	N/A
1	05/05/93	N/A
0	04/09/92	Initial issue of specification. Note: This specification supersedes *P4885-110-10*, "Pump Station Terminal Pipe Investigation Specification."

Records

None

3.5.4 Piping Recommended or Required for Removal from Service

When it is determined to have piping removed from service due to the results of the corrosion investigations, a visual inspection will be performed on the affected piping and any associated fittings before it is discarded. A person competent and experienced in corrosion engineering in Alyeska Integrity Management Engineering and/or a person directly associated with the PIT Program such as the Program CFE or Program Support Engineer shall perform the required inspections.

The results of the inspections will be documented on a Corrosion Investigation Report (CIR) and submitted to the Alyeska Integrity Management Engineering PIT Program Support Engineer. The hard copy of the CIR will be placed in the Integrity Management Engineering files and the PIT Program data base will be updated to reflect the removal of the piping and installation of new piping. As necessary (if existing inspection sites/grids affected) an electronic CIR will be completed in EDM identifying the results and piping replacement information. As a result of any newly installed piping, a baseline inspection will be scheduled under the PIT Program to take place not more than one year after the installation.

3.5.5 Inspection Documentation

Inspection documentation must be processed and maintained by receiving wall thickness data (grids) and field file records from the NDT contractor. The grids are to be processed by the IME and field analyzed per Section 3.5.1. The CIR information will be input in the CDM. NDT grid data shall be imported into the CDM. Results of the analysis will be summarized into a document named CID.

Transmit grids failing field analysis to the IME for further evaluation. The grid files and AUT files may be printed and stored with the field file records in the facility data books.

The data collected for the CIR is entered into the Electronic Data Management (EDM) system. The CIR *Form 10002* may be used for field purposes or shall be prepared upon request from IME and transmitted to IME upon completion to be filed in the corrosion records. The electronic CIR in the EDM system shall be used to document all piping inspections. The CIR form shall be used to document below ground piping inspections and aboveground to belowground piping transitions on B31.4 and B31.8 ("Gas Transmission and Distribution Piping Systems") piping systems for DOT and non-DOT piping. The PIR form can also be used to document B31.3 piping inspections if there is a need to utilize the additional sections provided on the PIR form to describe the piping conditions. All hardcopies of PIR forms shall be transmitted to the IME to be filed in the corrosion records.

Atmospheric corrosion evaluations are documented in the PIT Program data base files and electronic CIR form in EDM. As appropriate, a hard copy CIR will be completed and provided to the Integrity Management Engineering PIT Program Support Engineer to be placed into the Integrity Management Engineering corrosion files. Final assessment of external corrosion shall be made by the Alyeska Integrity Management PIT Program Support Engineer or their designee.

2.6.1.2 Permits

Permits may be required. See Section 1.10.

Obtain applicable Alyeska work permits before starting work. See *SA-38,* Requirement 1.15, "Work Permit System."

2.6.1.3 Pipe Inspection

1. Whenever any crude oil piping is removed from a pump station, Valdez Marine Terminal, or the mainline for any reason, the internal surface shall be inspected for evidence of corrosion. For inspection and reporting guidelines, see Section 17.4.2, "Pipe Inspections."
2. Whenever any buried crude oil or liquid piping is exposed at a pump station, Valdez Marine Terminal, or on the mainline for any reason, the external surface shall be inspected for evidence of corrosion. For inspection and reporting guidelines, see Section 17.4.2, "Pipe Inspections."

2.6.1.4 Pressure Reduction Process for Immediate Repair Conditions

If an immediate or severe integrity condition is reported by the in-line inspection (ILI) vendor and verified as such by an Alyeska engineer, an immediate pressure reduction will be required. This process is captured in Figure 2.1. OCC must be immediately notified of the pressure restriction. OCC will adjust operations to ensure that the pressure restriction set point is not exceeded. OCC will make all required notifications to regulatory agencies.

NOPV Response CPF 5-2008-5002
Exhibit 14
Page 1 of 2

stations' impressed current cathodic protection systems from the pipeline. Since original construction, electrical bonds have been installed across the isolation flanges to reduce the possibility of stray current interference.

Maintenance and modification activities near isolation flanges must be accomplished in a manner that does not compromise their function (i.e., avoid installing metal conduit that may provide an alternate current path around the isolation flange).

Integrity Management Engineering is responsible for determining where isolation flanges are to be installed and if any existing flanges should be electrically bonded. Installations of isolation flanges are case-specific and should be installed per the construction documents and manufacturer recommendations.

17.3.3 Separating Pipe

All piping systems, including the fuel gas line, main oil line, and pump station piping are electrically continuous. Piping should not be parted without employing bond straps to prevent the possibility of arcing associated with static charges or other voltage sources.

17.4 Corrosion Control

17.4.1 Responsibility

Integrity Management Engineering is responsible for the design, operation, and maintenance of TAPS cathodic protection systems and making recommendations to Alyeska management for improving and repairing those systems.

Integrity Management Engineering is responsible for maintaining cathodic protection records, and reports.

NOTE

Notify Integrity Management Engineering when problems with cathodic protection systems are discovered (e.g., damaged test stations, rectifiers, wires).

17.4.2 Pipe Inspections

As required by *49 CFR 195*, whenever the buried 48-inch mainline pipe is exposed for any reason, the exposed pipe surface must be inspected for evidence of corrosion. Perform inspections in accordance with Alyeska Specification *B-510, Mainline Pipe Investigation*. Form 3619, "Pipeline Investigation Report," must be completed in accordance with the specification and sent to Integrity Management Engineering. Form 3619 is available online from the TAPS Document System.

Whenever any DOT-regulated crude oil piping is removed, its internal surface and girth welds must be inspected for evidence of corrosion. Form 3619, "Pipeline Investigation Report," must be completed and sent to Integrity Management Engineering.

Whenever an inspection indicates extensive corrosion or coating deterioration, document the condition per *AMS-031, Inspection and Testing Process,* and *AMS-031-02, Procedure for Performing and Documenting Inspection.*

NOPV Response CPF 5-2008-5002
Exhibit 14
Page 2 of 2