POST INSPECTION MEMORANDUM

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JUN 11 2012

State of Washington
UTC
Pipeline Safety Program

Inspector: Kuang Chu & Dennis Ritter/UTC
Reviewed: Joe Subsits/WUTC
Peer Reviewed: RR
Follow-Up Enforcement: ~~No Violation~~
PCP* PCO* NOA WL LOC
Director Approval* CT 1/15/12
Revised: Issue WL 5/7/12

Date: November 17, 2011

OPID: 31522 **Region:** Western

RECEIVED

JUN 11 2012

WASH. UT. & TP. COMM

Operator Inspected:
KB Pipeline
121 SW Salmon Street
Portland, OR 97204

Unit Address:
KB Pipeline
PGE Beaver Power Plant
80997 Kallunki Road
Clatskanie, OR 97106

Unit Inspected: Western Washington **Unit ID:** 9775
Unit Type: Interstate Gas Transmission
Inspection Type: I01-Standard Inspection, I08-OQ Field Verification
Record Location: Clatskanie, OR
Inspection Dates: November 7-10, 2011
AFOD: 8.0 (I01-6.0, I08-2) (I01 6days) I08 - 2days
SMART Activity Number: #137313 #137314

emailed to J. Haddow 12/30/2011

Operator Contact: Robert Cosentino
Phone: (360) 200-4959 **Fax:** (530) 527-7176 **Emergency:** (800) 433-0252

Unit Description:
The Kelso-Beaver (KB) Pipeline is located in Cowlitz County, Washington. KB Pipeline takes delivery of natural gas from the Williams Northwest Pipeline meter station located east of Kelso, Washington and extends west approximately 18 miles to Columbia County, Oregon. The pipeline crosses under the Columbia River north of the City of Longview, Washington. The pipeline is a 20-inch diameter, API 5L grade X52 material, with a nominal wall thickness of 0.281, 0.344, and 0.375-inches. The pipeline is jointly owned by Portland General Electric (PGE), U.S. Gypsum Company, and Northwest Natural Gas (NWN). The K-B Pipeline has three customers located in Oregon at the PGE's Beaver generating station and Port Westward generating station, and U.S. Gypsum near Rainier, Oregon.

Facilities Inspected:
This inspection included a review of the records at PGE's Beaver generating station at Clatskanie, Oregon, and a field inspection of the pipeline right-of-way from the gate station located at the delivery point from Williams Gas Pipeline West located northeast of Longview, WA to the mainline valve KBV-3. Pipeline facilities inspected included the gate station, several cathodic protection test stations, road crossing casing under I-5 freeway, mainline valves, rectifier (only one in WA), above ground section of the pipeline, and land slide area.

Persons Interviewed:

Persons Interviewed	Title	Phone No.
Robert Cosentino	President & CEO, Cosentino Consulting Inc.	360-200-4959

Probable Violations/Concerns:
There was one probable violation as described below:

1) **§192.707 Line markers for mains and transmission lines.**
   (d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:
   (2) The name of the operator and telephone number (including area code) where the operator can be reached at all times.

   Finding(s):
   The operator for the KB Pipeline was changed from Cascade Natural Gas to KB Pipeline on April 1, 2011. The emergency phone number remains the same at 800-433-0252. During the field inspection, it was found that the emergency phone number was 800-433-1252 on newly installed markers. Further investigation revealed that the incorrect phone number was due to error made when ordering the new markers.

   Post inspection notes: Upon discovery of the mistake, the operator ordered new markers immediately locally. By Saturday November 12, 2011, all the markers with incorrect phone number have been replaced.

During Plan and Procedures review (PHMSA Form-1), the following deficiencies were identified in the operator's O&M manual. All the deficiencies were corrected immediately during the inspection.

1) **§192.615 Emergency plans.**
   a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
   (2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

Finding(s):
The list for appropriate fire, police, and other public officials in the operator's Emergency Procedure Manual Appendix C for emergency contacts was incomplete. The local law enforcement contact numbers for State Patrol and County Sheriff were not included in the manual.

2) **§192.225 Welding Procedures**

a) *Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API 1104 (incorporated by reference, see §192.7) or section IX of the ASME Boiler and Pressure Vessel Code "Welding and Brazing Qualifications" (incorporated by reference, see §192.7) to produce welds meeting the requirements of this subpart.*

Finding(s):
The operator's O&M manual Section 11.5.2 v for welding procedures did not include the edition number for API 1104, as required by §192.7 (c) (2) Documents incorporated by reference for API 1104, "Welding of Pipelines and Related Facilities" (20^{th} edition, October 2005, errata/addendum, (July 2007) and errata 2 (2008)).

3) **§192.476 Internal corrosion control: Design and construction of transmission line.**

(a) *Design and construction. Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:*

(1) *Be configured to reduce the risk that liquids will collect in the line;*
(2) *Have effective liquid removal features whenever the configuration would allow liquids to collect; and*
(3) *Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.*

Finding(s):
The requirements for internal corrosion control measures were not included in operator's O&M manual Section 11.2.2 for design and construction of transmission line.

Concern About Land Slide Area:
During the field inspection, the Hazel Dell Road Slide Area was inspected. The integrity of the pipeline at this location has been a great concern to us. In 2000, about 300 feet of pipe were raised above ground on steel structural supports to alleviate pipe stresses caused by ground movement. The landslide is active in this area and there were signs of additional ground movement under the steel structural supports since the last inspection in 2009. The majority owner of the pipeline (PGE) started monitoring ground movement over the pipeline by using survey by their own survey crew in 2000. Since 2006, PGE has been monitoring this area every two weeks during the rainy season (Nov. 1 through April 1), with additional monitoring

following a 2-inch rain event in a 24-hour period. During the dry season, monitoring takes place every six weeks. PGE stated that throughout the surveillance period, the pipe and the adjacent ground has not moved significantly in this area. During the field inspection, we noticed that there were scarps down-slope of the pipeline and up-slope of the pipeline with approximately 50 feet separating these two scarps (with the pipeline in the middle). We believe that the pipeline is under stress. But the magnitude of the stress is not known as there are no strain gages installed on the pipe and the survey started 8 years after the pipeline was built in 1992. There were no base lines for supposedly neutral position when the pipe was laid in the trench during original construction. In 2009, French drains were installed to improve drainage down-slope of the pipeline. During the exit interview, this subject was discussed extensively to convey our concern. The owner was urged to consider rerouting the pipeline or using horizontal directional drilling (HDD) to ensure the integrity of the pipeline.

Follow up on the history of prior offenses that are still open:

Prior Offenses (for the past 5 years)		
CPF #	**What type of open enforcement action(s)?**	**Status of the regulations(s) violated (Reoccurrence Offenses, Implement a NOA Revision, Completion of PCO or CO, and etc...)**

Recommendations:
1. Issue a NOPV for the pipeline markers.
2. This unit should continue to be inspected every other year.

Comments:
None.

Attachments:
PHMSA Form 1 - Standard Inspection Report of a Gas Transmission Pipeline
PHMSA Form 13 - Pipeline Drug &Alcohol Questions
PHMSA Form 15 - OQ Field Inspection Protocol
PHMSA Form 17 - Supplemental SCC Questionnaire Gas Transmission or Liquid Pipeline
Field Data Collection Form
Western Region-Unit Information Form

Version Date: 5/5/08

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	Kuang Chu, 11/18/2011	**Inspector/Submit Date:**	Kuang Chu, 11/18/2011
		Peer Review/Date:	Joe Subsits, 11/18/2011
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	KB Pipeline	**OPID #:**	31522
Name of Unit(s):	KB Pipeline	**Unit #(s):**	9775
Records Location:	PGE Beaver Power Plant, 80997 Kallunki Road in Clatskanie Oregon	**Activity #**	
Unit Type & Commodity:	Interstate Natural Gas Transmission		
Inspection Type:	Standard	**Inspection Date(s):**	11/7 – 10/2011
PHMSA Representative(s):	Kuang Chu & Dennis Ritter/UTC	**AFO Days:**	8

Company System Maps (copies for Region Files):	
Validate SMART Data (components, miles, etc): ☐	**Acquisition(s), Sale or New Construction** (submit SMART update): ☐
Validate Additional Requirements Resulting From Waiver(s) or Special Permit(s):	

Summary:

The Kelso-Beaver Pipeline Company is jointly owned by Portland General Electric (PGE), United States Gypsum Company, and Northwest Natural (NWN) Gas Company. The pipeline was constructed by NWN in 1992 and is operated by KB Pipeline. This inspection included a review of the records at PGE's Beaver Power Plant at Clatskanie, Oregon and a field inspection of the pipeline from the gate station located at the delivery point from Williams Northwest Pipeline located northeast of Longview, WA to the valve station KBV-03. The UTC is responsible for the segment from the Williams delivery point to the Columbia river, Washington/Oregon border. The segment from the Columbia river, Washington/Oregon border to the end point is the responsibility of the Western Region, PHMSA. The Oregon facilities were not part of this inspection.

Findings:

There was one probable violation as described below:

1) <u>§192.707 Line markers for mains and transmission lines.</u>
   (d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:
   (2) The name of the operator and telephone number (including area code) where the operator can be reached at all times.

<u>Findings:</u>
The operator for the KB Pipeline was changed from Cascade Natural Gas to KB Pipeline on April 1, 2011. The emergency phone number remains the same at 800-433-0252. During the field inspection, it was found that the emergency phone number was 800-433-1252 on newly installed markers. Further investigation revealed that the incorrect phone number was due to error made when ordering the new markers.

<u>Post inspection notes:</u> Upon discovery of the mistake, the operator ordered new markers immediately locally. By Saturday November 12, 2011, all the markers with incorrect phone number have been replaced.

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

During Plan and Procedures review (PHMSA Form-1), the following deficiencies were identified in the operator's O&M manual. All the deficiencies were corrected immediately during the inspection.

1) <u>§192.615 Emergency plans.</u>

   a) **Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:**

      (2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

   <u>**Findings:**</u>

   The list for appropriate fire, police, and other public officials in the operator's Emergency Procedure Manual Appendix C for emergency contacts was incomplete. The local law enforcement contact numbers for State Patrol and County Sheriff were not included in the manual.

2) <u>§192.225 Welding Procedures</u>

   a) **Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API 1104 (incorporated by reference, see §192.7) or section IX of the ASME Boiler and Pressure Vessel Code " Welding and Brazing Qualifications" (incorporated by reference, see §192.7) to produce welds meeting the requirements of this subpart.**

   <u>**Findings:**</u>

   The operator's O&M manual Section 11.5.2 v for welding procedures did not include the edition number for API 1104, as required by §192.7 (c) (2) Documents incorporated by reference for API 1104, "Welding of Pipelines and Related Facilities" (20^{th} edition, October 2005, errata/addendum, (July 2007) and errata 2 (2008)).

3) <u>§192.476 Internal corrosion control: Design and construction of transmission line.</u>

   (a) **Design and construction. Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:**

   (1) Be configured to reduce the risk that liquids will collect in the line;

   (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

   (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

   <u>**Findings:**</u>

   The requirements for internal corrosion control measures were not included in operator's O&M manual Section 11.2.2 for design and construction of transmission line.

<u>**Concern About Land Slide Area:**</u>

During the field inspection, the Hazel Dell Road Slide Area was inspected. The integrity of the pipeline at this location has been a great concern to us. In 2000, about 300 feet of pipe were raised above ground on steel structural supports to alleviate pipe stresses caused by ground movement. The landslide is active in this area and there were signs of additional ground movement under the steel structural supports since the last inspection in 2009. The majority owner of the pipeline (PGE) started monitoring ground movement over the pipeline by using survey by their own survey crew in 2000. Since 2006, PGE has been monitoring this area every two weeks during the rainy season (Nov. 1 through April 1), with additional monitoring following a 2-inch rain event in a 24-hour period. During the dry season, monitoring takes place every six weeks. PGE stated that throughout the surveillance period, the pipe and the adjacent ground has not moved significantly in this area. During the field inspection, we noticed that there were scarps down-slope of the pipeline and up-slope of the pipeline with approximately 50 feet separating these two scarps (with the pipeline in the middle). We believe that the pipeline is under stress. But the magnitude of the stress is not known as there are no strain gages installed on the pipe and the survey started 8 years after the pipeline was built in 1992. There were no base lines for supposedly neutral position when the pipe was laid in the trench during original construction. In 2009, French drains were installed to improve drainage down-slope of the pipeline. During the exit interview, this subject was discussed extensively to convey our concern. The owner was urged to consider rerouting the pipeline or using horizontal directional drilling (HDD) to ensure the integrity of the pipeline.

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

Name of Operator:	KB Pipeline		
OP ID No. [1]	31522	**Unit ID No.** [1]	9775
HQ Address:		**System/Unit Name & Address:** [1]	
121 SW Salmon Street Portland, OR 97204		80997 Kallunki Road Clatskanie, OR 97106	
Co. Official:	Bill Nicholson	**Activity Record ID No.:**	
Phone No.:	503.464.8855	**Phone No.:**	503.464.8855
Fax No.:	503.464.2222	**Fax No.:**	503.464.2222
Emergency Phone No.:	800.433.0252	**Emergency Phone No.:**	800.433.0252

Persons Interviewed	**Title**	**Phone No.**
Robert Cosentino	President & CEO, Cosentino Consulting Inc.	360.200.4959

PHMSA Representative(s) [1]	Kuang Chu & Dennis Ritter/UTC	**Inspection Date(s)** [1]	11/7 – 10/2011
Company System Maps (Copies for Region Files):			

Unit Description:
The Kelso-Beaver (K-B) Pipeline is located in Cowlitz County, Washington. K-B Pipeline takes delivery of natural gas from the Williams Northwest Pipeline meter station located east of Kelso, Washington and extends west approximately 18 miles to Columbia County, Oregon. The pipeline crosses under the Columbia River north of the City of Longview, Washington. The pipeline is a 20-inch diameter, API 5L grade X52 material, with a nominal wall thickness of 0.281, 0.344, and 0.375-inches. The pipeline is jointly owned by Portland General Electric (PGE), U.S. Gypsum Company, and Northwest Natural Gas (NWN). The K-B Pipeline has three customers located in Oregon at the PGE's Beaver generating station and Port Westward generating station, and U.S. Gypsum near Rainier, Oregon.

Portion of Unit Inspected: [1]
This inspection included a review of the records at PGE's Beaver generating station at Clatskanie, Oregon, and a field inspection of the pipeline right-of-way from the gate station located at the delivery point from Williams Gas Pipeline West located northeast of Longview, WA to the mainline valve KBV-3. Pipeline facilities inspected included the gate station, several cathodic protection test stations, road crossing casing under I-5 freeway, mainline valves, rectifier (only one in WA), above ground section of the pipeline, and land slide area.

For gas transmission pipeline inspections, the attached evaluation form should be used in conjunction with 49 CFR 191 and 192 during PHMSA inspections. For those operators, procedures do not have to be evaluated for content unless: 1) new or amended regulations have been placed in force after the team inspection, or 2) procedures have changed since the team inspection. Items in the procedures sections of this form identified with "*" reflect applicable and more restrictive new or amended regulations that became effective between 03/16/06 and 03/17/2011.

[1] Information not required if included on page 1.

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

Unless otherwise noted, all code references are to 49CFR Part 192. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked

If an item is marked U, N/A, or N/C, an explanation must be included in this report.

	NPMS INFORMATION and UPDATE	Yes	No
	Did the operator submit their pipeline information to NPMS and did they submit any updates or changes? 49 U.S.C. 60132 and ADB-08-07	x	

49 CFR PART 191

	REPORTING PROCEDURES	S	U	N/A	N/C
.605(b)(4)	Procedures for gathering data for incident reporting				
	191.5 Immediate Notice of certain incidents to NRC **(800) 424-8802,** or electronically at http://www.nrc.uscg.mil/nrchp.html, and additional report if significant new information becomes available. (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	x			
*	191.7 Reports (except SRCR and offshore pipeline condition reports) must be submitted electronically to PHMSA at https://opsweb.phmsa.dot.gov unless an alternative reporting method is authorized IAW with paragraph (d) of this section. (Amdt. 191-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	x			
*	191.15(a) 30-day follow-up written report **(Form 7100-2)** Submittal must be electronically to http://pipelineonlinereporting.phmsa.dot.gov (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	x			
*	191.15(c) Supplemental report (to 30-day follow-up)	x			
.605(a) *	191.17 Complete and submit DOT Form PHMSA F 7100-2.1 by March 15 of each calendar year for the preceding year. *(NOTE: June 15, 2011 for the year 2010).* (Amdt. 192-115, 75 FR 72878, November 26, 2010).	x			
*	191.22 Each operator must obtain an OPID, validate its OPIDs, and notify PHMSA of certain events at https://opsweb.phmsa.dot.gov (Amdt. 192-115, 75 FR 72878, November 26, 2010, eff. 1/1/2011).	x			
	191.23 Reporting safety-related condition (SRCR	x			
	191.25 Filing the SRCR within 5 days of determination, but not later than 10 days after discovery	x			
	191.27 Offshore pipeline condition reports – filed within 60 days after the inspections (**Notes: There are no offshore pipelines in this unit.)**			x	
.605(d)	Instructions to enable operation and maintenance personnel to recognize potential **Safety Related Conditions**	x			

Comments:

49 CFR PART 192

.13(c)	CUSTOMER NOTIFICATION PROCEDURES	S	U	N/A	N/C
	.16 Procedures for notifying new customers, within **90 days**, of their responsibility for those selections of service lines not maintained by the operator.	x			

.14	CONVERSION OF SERVICE PROCEDURES	S	U	N/A	N/C
	A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:				
	.14(a)(1) Review of the design, construction operation and maintenance history	x			
	.14(a)(2) Visual Right-of-way and pipeline inspection for physical defects and operating conditions.	x			
	.14(a)(3) Correction of known unsafe defects and conditions.	x			
	.14(a)(4) Pipeline tested in accordance with Subpart J.	x			

.605(a)	NORMAL OPERATING and MAINTENANCE PROCEDURES	S	U	N/A	N/C
	.605(a) O&M Plan review and update procedure (**1 per year/15 months)**	x			

			S	U	N/A	N/C
	.605(b)(3)	Making construction records, maps, and operating history available to appropriate operating personnel	x			
	.605(b)(5)	Start up and shut down of the pipeline to assure operation within MAOP plus allowable buildup	x			
	.605(b)(8)	Periodically reviewing the work done by operator's personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found	x			
	.605(b)(9)	Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapors or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and a rescue harness and line	x			
	.605(b)(10)	Routine inspection and testing of pipe-type or bottle-type holders **(Notes: There are no pipe-type or bottle-type holders in this unit.)**			x	
	.605(b)(11)	Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedure under §192.615(a)(3) specifically apply to these reports.	x			
*	.605(b)(12)	Implementing the applicable control room management procedures required by 192.631. (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010). **(Notes: The CRM procedures do not apply to this unit.)**			x	

Comments:

.605(a)		ABNORMAL OPERATING PROCEDURES	S	U	N/A	N/C
	.605(c)(1)	Procedures for responding to, investigating, and correcting the cause of:				
		(i) Unintended closure of valves or shut downs	x			
		(ii) Increase or decrease in pressure or flow rate outside of normal operating limits	x			
		(iii) Loss of communications	x			
		(iv) The operation of any safety device	x			
		(v) Malfunction of a component, deviation from normal operations or personnel error	x			
	.605(c)(2)	Checking variations from normal operation after abnormal operations ended at sufficient critical locations	x			
	.605(c)(3)	Notifying the responsible operating personnel when notice of an abnormal operation is received	x			
	.605(c)(4)	Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found	x			

Comments:

.605(a)		CHANGE in CLASS LOCATION PROCEDURES	S	U	N/A	N/C
	.609	Class location study	x			
*	.611	Confirmation or revision of MAOP. Final Rule Pub. 10/17/08, eff. 12/22/08.	x			

Comments:

Comments:

.613		CONTINUING SURVEILLANCE PROCEDURES	S	U	N/A	N/C
	.613(a)	Procedures for surveillance and required actions relating to change in class location, failures, leakage history, corrosion, substantial changes in **CP** requirements, and unusual operating and maintenance conditions	x			
	.613(b)	Procedures requiring **MAOP** to be reduced, or other actions to be taken, if a segment of pipeline is in unsatisfactory condition	x			

Comments:

.605(a)		DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
	.614	Participation in a qualified one-call program, or if available, a company program that complies with the following:				
		(1) Identify persons who engage in excavating	x			
		(2) Provide notification to the public in the One Call area	x			
		(3) Provide means for receiving and recording notifications of pending excavations	x			
		(4) Provide notification of pending excavations to the members	x			
		(5) Provide means of temporary marking for the pipeline in the vicinity of the excavations	x			
		(6) Provides for follow-up inspection of the pipeline where there is reason to believe the pipeline could be damaged	x			
		(i) Inspection must be done to verify integrity of the pipeline	x			
		(ii) After blasting, a leak survey must be conducted as part of the inspection by the operator	x			

Comments:

.615		EMERGENCY PROCEDURES	S	U	N/A	N/C
	.615(a)(1)	Receiving, identifying, and classifying notices of events which require immediate response by the operator	x			
	.615(a)(2)	Establish and maintain communication with appropriate public officials regarding possible emergency **(Notes: The list of public officials for emergency contacts was not complete during the inspection. It was updated immediately right after the inspection.)**		x		
	.615(a)(3)	Prompt response to each of the following emergencies:				
		(i) Gas detected inside a building	x			
		(ii) Fire located near a pipeline	x			
		(iii) Explosion near a pipeline	x			
		(iv) Natural disaster	x			

			S	U	N/A	N/C
	.615(a)(4)	Availability of personnel, equipment, instruments, tools, and material required at the scene of an emergency	x			
	.615(a)(5)	Actions directed towards protecting people first, then property	x			
	.615(a)(6)	Emergency shutdown or pressure reduction to minimize hazards to life or property	x			
	.615(a)(7)	Making safe any actual or potential hazard to life or property	x			
	.615(a)(8)	Notifying appropriate public officials required at the emergency scene and coordinating planned and actual responses with these officials	x			
	.615(a)(9)	Instructions for restoring service outages after the emergency has been rendered safe	x			
*	.615(a)(10)	Investigating accidents and failures as soon as possible after the emergency	x			
	.615(a)(11)	Actions required to be taken by a controller during an emergency in accordance with 192.631. (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010).			x	
	.615(b)(1)	Furnishing applicable portions of the emergency plan to supervisory personnel who are responsible for emergency action	x			
	.615(b)(2)	Training appropriate employees as to the requirements of the emergency plan and verifying effectiveness of training	x			
	.615(b)(3)	Reviewing activities following emergencies to determine if the procedures were effective	x			
	.615(c)	Establish and maintain liaison with appropriate public officials, such that both the operator and public officials are aware of each other's resources and capabilities in dealing with gas emergencies **(Notes: The list of public officials was not complete during the inspection. It was updated immediately right after the inspection.)**		x		

Comments:

PUBLIC AWARENESS PROGRAM PROCEDURES

(Also in accordance with API RP 1162)

(Notes: A joint PHMSA/UTC inspection for Public Awareness Program was conducted for this operator in October 2011. This inspection did not repeat that inspection.)

				S	U	N/A	N/C
.605(a)	**.616**	Public Awareness Program also in accordance with API RP 1162.					
	.616(d)	The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:					
		(1)	Use of a one-call notification system prior to excavation and other damage prevention activities;				x
		(2)	Possible hazards associated with unintended releases from a gas pipeline facility;				x
		(3)	Physical indications of a possible release;				x
		(4)	Steps to be taken for public safety in the event of a gas pipeline release; and				x
		(5)	Procedures to report such an event (to the operator).				x
	.616(e)	The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.					x
	.616(f)	The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports gas.					x
	.616(g)	The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area?					x
	.616(h)	IAW API RP 1162, the operator's program should be reviewed for effectiveness within four years of the date the operator's program was first completed. <u>For operators in existence on June 20, 2005</u>, who must have completed their written programs no later than June 20, 2006, the first evaluation is due no later than **June 20, 2010**.					x

Comments:

.617	**FAILURE INVESTIGATION PROCEDURES**		S	U	N/A	N/C
	.617	Analyzing accidents and failures including laboratory analysis where appropriate to determine cause and prevention of recurrence	x			

Comments:

.605(a)	**MAOP PROCEDURES**		S	U	N/A	N/C
	Note: If the operator is operating under a Special Permit, a Waiver or 192.620, the inspector needs to review the special conditions of the Special Permit, Waiver or refer to Attachment 1 for additional .620 requirements.					
	.619	Establishing **MAOP** so that it is commensurate with the class location	x			
		MAOP cannot exceed the lowest of the following:				
*		(a)(1) Design pressure of the weakest element, Amdt. 192-103 pub. 06/09/06, eff. 07/10/06	x			
		(a)(2) Test pressure divided by applicable factor	x			
*		(a)(3) The highest actual operating pressure to which the segment of line was subjected during the 5 years preceding the applicable date in second column, unless the segment was tested according to .619(a)(2) after the applicable date in the third column or the segment was uprated according to subpart K. Amdt 192-102 pub. 3/15/06, eff. 04/14/06. **For gathering line related compliance deadlines and additional gathering line requirements, refer to Part 192 including this amendment.**			x	

Pipeline segment	Pressure date	Test date
--Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006. -- Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines.	July 1, 1976.	July 1, 1971.
All other pipelines.	July 1, 1970.	July 1, 1965.

			S	U	N/A	N/C
		(a)(4) Maximum safe pressure determined by operator.			x	
		(b) Overpressure protective devices must be installed if .619(a)(4) is applicable			x	
*		(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611. Amdt 192-102 pub. 3/15/06, eff. 04/14/06. **For gathering line related compliance deadlines and additional gathering line requirements, refer to Part 192 including this amendment.**			x	
*	.620	Refer to Attachment 1 for additional Alternative MAOP requirements. (Amdt. 192- 107, 73 FR 62147, October 17, 2008, eff. 11/17/2008).				

Comments:

Comments:

.13(c)	PRESSURE TEST PROCEDURES	S	U	N/A	N/C
	.503 Pressure testing	x			

Comments:

.13(c)	UPRATING PROCEDURES	S	U	N/A	N/C
	.553 Uprating **(Notes: This unit will never be uprated.)**			x	

Comments:

.605(a)	ODORIZATION of GAS PROCEDURES		S	U	N/A	N/C
	.625(b)	Odorized gas in **Class 3** or **4** locations (if applicable) – must be readily detectable by person with normal sense of smell at $^1/_5$ of the LEL	x			
	.625(f)	Periodic gas sampling, using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.	x			

Comments:

.605(a)	TAPPING PIPELINES UNDER PRESSURE PROCEDURES		S	U	N/A	N/C
	.627	Hot taps must be made by a qualified crew **NDT** testing is suggested prior to tapping the pipe. Reference API RP 2201 for **Best Practices.**	x			

.605(a)	PIPELINE PURGING PROCEDURES		S	U	N/A	N/C
	.629	Purging of pipelines must be done to prevent entrapment of an explosive mixture in the pipeline				
		(a) Lines containing air must be properly purged.	x			
		(b) Lines containing gas must be properly purged	x			

Comments:

*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010) **(Notes: The CRM procedures do not apply to this unit.)**		S	U	N/A	N/C
.605(a)	.631(a)	(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system, except where an operator's activities are limited to: (ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.					
	.631(a)	.605(b)(12) Each operator must have and follow written control room management procedures. NOTE: *An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than February 1, 2013.*					
	.631(b)	The operator's program must define the roles and responsibilities of a controller during normal, abnormal and emergency conditions including a definition of:					
		(1)	Controller's authority and responsibility.			x	
		(2)	Controller's role when an abnormal operating condition is detected.			x	
		(3)	Controller's role during an emergency			x	
		(4)	A method of recording shift change responsibilities between controllers.			x	
	.631(c)	The operator's program must provide its controllers with the information, tools, processes and procedures necessary to perform each of the following:					
		(1) Implement sections 1, 4, 8,9,11.2, and 11.3 of API RP 1165 whenever a SCADA System is added, expanded or replaced.				x	
		(2) Conduct point-to-point verification between SCADA displays and related equipment when changes that affect pipeline safety are made.				x	
		(3) Test and verify any internal communications plan – at least once a year NTE 15 months.				x	
		(4) Test any backup SCADA system at least once each year but NTE 15 months.				x	
		(5) Establish and implement procedures for when a different controller assumes responsibility.				x	
	.631(d)	Each operator must implement and follow methods to reduce the risk associated with controller fatigue, including:					
		(1) Establishing shift lengths and schedule rotations that provide time sufficient to achieve eight hours of continuous sleep.				x	
		(2) Educating controllers and supervisors in fatigue mitigation strategies.				x	
		(3) Training of controllers and supervisors to recognize the effects of fatigue.				x	
		(4) Establishing a maximum limit on controller hours-of-service.				x	
	.631(e)	Each operator must have a written alarm management plan including these provisions:					
		(1) Reviewing alarms using a process that ensures that they are accurate and support safe operations.				x	
		(2) Identifying at least once a year, points that have been taken off SCADA scan or have had alarms inhibited, generated false alarms, or have had forced or manual values for periods of time exceeding that required for maintenance activities.				x	
		(3) Verifying the alarm set-point values and alarm descriptions once each year NTE 15 months.				x	
		(4) Reviewing the alarm management plan at least once every calendar year NTE 15 months.				x	
		(5) Monitoring the content and volume of activity being directed to and required of each controller once each year NTE 15 months.				x	
		(6) Addressing deficiencies identified through implementation of 1-5 of this section.				x	
	.631(f)	Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing the following:					
		(1) Establishing communications between controllers, management and field personnel when implementing physical changes to the pipeline.				x	
		(2) Requiring field personnel to contact the control room when emergency conditions exist and when field changes could affect control room operations.				x	

		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010) **(Notes: The CRM procedures do not apply to this unit.)**	S	U	N/A	N/C
		(3) Seeking control room or management participation in planning prior to implementation of significant pipeline changes.			x	
	.631(g)	Each operator must assure that lessons learned from its experience are incorporated in to its procedures by performing the following:				
		(1) Reviewing reportable incidents to determine if control room actions contributed to the event and correcting any deficiencies.			x	
		(2) Including lessons learned from the operator's training program required by this section.			x	
	.631(h)	Each operator must establish a controller training program and review its contents once a year NTE 15 months which includes the following elements:			x	
		(1) Responding to abnormal operating conditions (AOCs).			x	
		(2) Using a computerized simulator or other method for training controllers to recognize AOCs			x	
		(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures.			x	
		(4) Training that provides a working knowledge of the pipeline system, especially during AOCs.			x	
		(5) Providing an opportunity for controllers to review relevant procedures for infrequently used operating setups.			x	

Comments:

.605(a)		**MAINTENANCE PROCEDURES**	S	U	N/A	N/C
	.703(b)	Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service	x			
	(c)	Hazardous leaks must be repaired promptly	x			

Comments:

.605(b)		**TRANSMISSION LINES - PATROLLING & LEAKAGE SURVEY PROCEDURES**	S	U	N/A	N/C
	.705(a)	Patrolling ROW conditions	x			
	(b)	Maximum interval between patrols of lines: (see table below)	x			
	.706	Leakage surveys – **1 year/15 months**	x			
		Leak **detector equipment** survey requirements for lines transporting un-odorized gas				
		(a) **Class 3 locations - 7½ months** but at least **twice each calendar year**	x			

Class Location	At Highway and Railroad Crossings	At All Other Places
1 and 2	2/yr (7½ months)	1/yr (15 months)
3	4/yr (4½ months)	2/yr (7½ months)
4	4/yr (4½ months)	4/yr (4½ months)

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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.605(b)	TRANSMISSION LINES - PATROLLING & LEAKAGE SURVEY PROCEDURES	S	U	N/A	N/C
	(b) **Class 4** locations - **4½ months** but at least **4 times each calendar year**	x			

Comments:

.605(b)	LINE MARKER PROCEDURES	S	U	N/A	N/C
.707	Line markers installed and labeled as required	x			

Comments:

.605(b)	RECORD KEEPING PROCEDURES	S	U	N/A	N/C
.709	Records must be maintained:				
	(a) Repairs to the pipe – **life of system**	x			
	(b) Repairs to "other than pipe" – **5 years**	x			
	(c) Operation (Sub L) and Maintenance (Sub M) patrols, surveys, tests – **5 years** or until next one	x			

Comments:

.605(b)	FIELD REPAIR PROCEDURES	S	U	N/A	N/C
	Imperfections and Damages				
.713(a)	Repairs of imperfections and damages on pipelines operating above **40% SMYS**				
	(1) Cut out a cylindrical piece of pipe and replace with pipe of ≥ design strength	x			
	(2) Use of a reliable engineering method	x			
.713(b)	Reduce operating pressure to a safe level during the repair	x			
	Permanent Field Repair of Welds				
.715	Welds found to be unacceptable under §192.241(c) must be repaired by:				
	(a) If feasible, taking the line out of service and repairing the weld in accordance with the applicable requirements of **§192.245.**	x			
	(b) If the line remains in service, the weld may be repaired in accordance with **§192.245** if:				
	(1) The weld is not leaking	x			
	(2) The pressure is reduced to produce a stress that is **20% of SMYS or less**	x			
	(3) Grinding is limited so that **⅛ inch** of pipe weld remains	x			
	(c) If the weld cannot be repaired in accordance with **(a) or (b)** above, a full encirclement welded split sleeve must be installed	x			
	Permanent Field Repairs of Leaks				
.717	Field repairs of leaks must be made as follows:				
	(a) Replace by cutting out a cylinder and replace with pipe similar or of greater design	x			
	(b)(1) Install a full encirclement welded split sleeve of an appropriate design unless the pipe is **joined by mechanical couplings** and **operates at less than 40% SMYS**	x			

.605(b)		FIELD REPAIR PROCEDURES	S	U	N/A	N/C
	(b)(2)	A leak due to a corrosion pit may be repaired by installing **a bolt on leak clamp**	x			
	(b)(3)	For a corrosion pit leak, if a pipe is not more than **40,000 psi SMYS**, the pits may be repaired by **fillet welding a steel plate.** The plate must have **rounded corners** and the same **thickness or greater** than the pipe, and **not more than ½D** of the pipe size **(Notes: The pipe material is API 5L grade X-52. Patches will not be used for repairs for this line.))**			x	
	(b)(4)	Submerged offshore pipe or pipe in inland navigable waterways may be repaired with a mechanically applied full encirclement split sleeve of appropriate design **(Notes: There are no offshore pipelines in this unit.)**			x	
	(b)(5)	Apply reliable engineering method	x			
		Testing of Repairs				
	.719(a)	Replacement pipe must be pressure tested to meet the requirements of a new pipeline	x			
	(b)	For lines of **6-inch diameter or larger** and that **operate at 20% of more of SMYS,** the repair must be nondestructively tested in accordance with **§192.241(c)**	x			

Comments:

.605(b)		ABANDONMENT or DEACTIVATION of FACILITIES PROCEDURES	S	U	N/A	N/C
	.727(b)	Operator must disconnect both ends, purge, and seal each end before abandonment or a period of deactivation where the pipeline is not being maintained. Offshore abandoned pipelines must be filled with water or an inert material, with the ends sealed	x			
	(c)	Except for service lines, each inactive pipeline that is not being maintained under Part 192 must be disconnected from all gas sources/supplies, purged, and sealed at each end.	x			
	(d)	Whenever service to a customer is discontinued, do the procedures indicate one of the following:				
		(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator **(Notes: This unit is not a gas distribution system.)**			x	
		(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly **(Notes: This unit is not a gas distribution system.)**			x	
		(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed **(Notes: This unit is not a gas distribution system.)**			x	
	(e)	If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging	x			
*	.727 (g)	Operator must file reports upon abandoning underwater facilities crossing navigable waterways, including offshore facilities. Amdt. 192-103 corr. pub 02/01/07, eff. 03/05/07.	x			

Comments:

.605(b)		COMPRESSOR STATION PROCEDURES **(Notes: The unit does not have compressor stations.)**	S	U	N/A	N/C
	.605(b)(6)	Maintenance procedures, including provisions for isolating units or sections of pipe and for purging before returning to service			x	

			S	U	N/A	N/C
	.605(b)(7)	Starting, operating, and shutdown procedures for gas compressor units			x	
	.731	Inspection and testing procedures for remote control shutdowns and pressure relieving devices **(1 per yr/15 months)**, prompt repair or replacement			x	
*	.735	(a) Storage of excess flammable or combustible materials at a safe distance from the compressor buildings			x	
		(b) Tank must be protected according to **NFPA #30**; Amdt 192-103 pub. 06/09/06 eff. 07/10/06.			x	
	.736	Compressor buildings in a compressor station must have fixed gas detection and alarm systems **(must be performance tested)**, unless:			x	
		▪ **50% of the upright side areas** are permanently open, or			x	
		▪ It is an unattended field compressor station of **1000 hp or less**			x	

Comments:

.605(b)		PRESSURE LIMITING and REGULATING STATION PROCEDURES	S	U	N/A	N/C
	.739(a)	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment **(1 per yr/15 months)**	x			
		(1) In good mechanical condition	x			
		(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed	x			
	.739(a)	(3) Set to control or relieve at correct pressures consistent with .201(a), except for .739(b).	x			
		(4) Properly installed and protected from dirt, liquids, other conditions that may prevent proper oper.	x			
	.739(b)	For steel lines if MAOP is determined per .619(c) and the MAOP is 60 psi (414 kPa) gage or more . . . **(Notes: The MAOP of the system was not determined per .619(c).)**				
		If MAOP produces hoop stress that / Then the pressure limit is: Is greater than 72 percent of SMYS / MAOP plus 4 percent Is unknown as a percent of SMYS / A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP			x	
	.743	Testing of Relief Devices **(Notes: The pressure relief devices is at Williams meter station. The unit does not have pressure relief valves.)**				
	.743	(a) Capacity must be consistent with .201(a) except for .739(b), and be determined **1 per yr/15 mo.**			x	
	.743	(b) If calculated, capacities must be compared; annual review and documentation are required.			x	
	.743	(c) If insufficient capacity, new or additional devices must be installed to provide required capacity.			x	

Comments:

.605(b)		VALVE MAINTENANCE PROCEDURES	S	U	N/A	N/C
	.745	(a) Inspect and partially operate each transmission valve that might be required during an emergency **(1 per yr/15 months)**	x			
	.745	(b) Prompt remedial action required, or designate alternative valve.	x			

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.605(b)	VAULT INSPECTION PROCEDURES	S	U	N/A	N/C
.749	Inspection of vaults greater than **200 cubic feet** and housing pressure regulating or limiting devices (**1 per yr NTE 15 months**). **(Notes: The unit does not have vaults.)**			x	

Comments:

.605(b)	PREVENTION of ACCIDENTAL IGNITION PROCEDURES	S	U	N/A	N/C
.751	Reduce the hazard of fire or explosion by:				
	(a) Removal of ignition sources in presence of gas and providing for a fire extinguisher	x			
	(b) Prevent welding or cutting on a pipeline containing a combustible mixture	x			
	(c) Post warning signs	x			

Comments:

.13(c)	WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A	N/C
* .225	(a) Welding procedures must be qualified under **Section 5 of API 1104** or **Section IX of ASME Boiler and Pressure Code** by destructive test. Amdt. 192-103 pub 06/09/06, eff. 07/10/06. **(Notes: The operator's O&M manual did not include 20th edition, October 2005 of API 1104 as the standard for compliance. The O&M manual was revised immediately following the inspection.)**		x		
*	(b) Retention of welding procedure – details and test	x			
Note: Alternate welding procedures criteria are addressed in API 1104 Appendix A, section A.3.					
.227	(a) Welders must be qualified by **Section 6 of API 1104 (20th edition 2007, including errata 2008)** or **Section IX of the ASME Boiler and Pressure Vessel Code (2007 edition, July 1, 2007)**, except that a welder qualified under an earlier edition than currently listed in 192.7 may weld, but may not requalify under that earlier edition. (Amdt 192-114 Pub. 8/11/10 eff. 10/01/10). **(Notes: This unit does not have compressor stations.)**			x	
	(b) Welders may be qualified under **section I of Appendix C** to weld on lines that operate at **< 20% SMYS. (Notes: The MAOP of the pipeline is over 20% SMYS.)**			x	
.229	(a) To weld on compressor station piping and components, a welder must successfully complete a destructive test **(Notes: This unit does not have compressor stations.)**			x	
	(b) Welder must have used welding process within the preceding **6 months**	x			
	(c) A welder qualified under .227(a) –				
.229(c)	(1) May not weld on pipe that operates at ≥ 20% SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the **sections 6 or 9 of API Standard 1104**; may maintain an ongoing qualification status by performing welds tested and found acceptable at least **twice per year**, not exceeding **7½ months**; may not requalify under an earlier referenced edition.	x			
	(2) May not weld on pipe that operates at < 20% SMYS unless is tested in accordance with .229(c)(1) or requalifies under .229(d)(1) or (d)(2). **(Notes: The MAOP of the pipeline is over 20% SMYS.)**			x	
	(d) Welders qualified under .227(b) may not weld unless: **(Notes: The MAOP of the pipeline is over 20% SMYS.)**				

.13(c)			**WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES**	S	U	N/A	N/C
			(1) Requalified within **1 year/15 months**, or			x	
	N/A		(2) Within **7½ months** but at least **twice per year** had a production weld pass a qualifying test			x	
	.231		Welding operation must be protected from weather	x			
	.233		Miter joints (**consider pipe alignment**)	x			
	.235		Welding preparation and joint alignment **Alert Notice 3/24/10**: Do operator's procedures give consideration to girth weld bevels being properly transitioned and aligned, girth weld pipe ends meeting API 5L pipe end diameter and diameter out-of-roundness specifications, and API 1104 alignment and allowable "high-low" criteria, particularly in large diameter pipe (> 20" diameter)?	x			
	.241	(a)	Visual inspection must be conducted by an individual qualified by appropriate training and experience to ensure:	x			
			(1) Compliance with the welding procedure	x			
			(2) Weld is acceptable in accordance with **Section 9 of API 1104**	x			
		(b)	Welds on pipelines to be **operated at 20% or more of SMYS** must be nondestructively tested in accordance with **192.243** except welds that are visually inspected and approved by a qualified welding inspector if:	x			
			(1) The nominal pipe diameter is less than **6 inches**, or **(Notes: The KB line is a 20" pipeline.)**			x	
	(Notes: The MAOP is over 40% SMYS.)		(2) The pipeline is to operate at a pressure that produces a hoop stress of less than **40% of SMYS** and the welds are so limited in number that nondestructive testing is impractical			x	
	.241	(c)	Acceptability based on visual inspection or NDT is determined according to **Section 9 of API 1104.** If a girth weld is unacceptable under **Section 9** for a reason other than a crack, and if **Appendix A to API 1104** applies to the weld, the acceptability of the weld may be further determined under that appendix.	x			
	Note: If the alternative acceptance criteria in API 1104 Appendix A are used, has the operator performed an Engineering Critical Assessment (ECA)?						
	.245		Repair and Removal of Weld Defects				
		(a)	Each weld that is unacceptable must be removed or repaired. Except for offshore pipelines, a weld must be removed if it has a crack that is more than **8%** of the weld length	x			
		(b)	Each weld that is repaired must have the defect removed down to sound metal, and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the weld must be inspected and found acceptable.	x			
		(c)	Repair of a crack or any other defect in a previously repaired area must be in accordance with a written weld repair procedure, qualified under §192.225	x			
			Note: Sleeve Repairs – use low hydrogen rod (**Best Practices –ref. API 1104 App. B, In Service Welding**)				

Comments:

.13(c)			**NONDESTRUCTIVE TESTING PROCEDURES**	S	U	N/A	N/C
	.243	(a)	Nondestructive testing of welds must be performed by any process, other than trepanning, that clearly indicates defects that may affect the integrity of the weld	x			
		(b)	Nondestructive testing of welds must be performed:				
			(1) In accordance with a written procedure, and	x			
			(2) By persons trained and qualified in the established procedures and with the test equipment used	x			

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.13(c)		NONDESTRUCTIVE TESTING PROCEDURES	S	U	N/A	N/C
	(c)	Procedures established for proper interpretation of each nondestructive test of a weld to ensure acceptability of the weld under **192.241(c)**	x			
	(d)	When nondestructive testing is required under **§192.241(b)**, the following percentage of each day's field butt welds, selected at random by the operator, must be nondestructively tested over the entire circumference **(Notes: All field butt welds are 100% nondestructively tested by using x-ray.)**				
		(1) In **Class 1** locations at least **10%**			x	
		(2) In **Class 2** locations at least **15%**			x	
		(3) In **Class 3** and **4** locations, at crossings of a major navigable river, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, **100%** unless impractical, then **90%**. Nondestructive testing must be impractical for each girth weld not tested.	x			
		(4) At pipeline tie-ins, **100%**	x			
	(e)	Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under **§192.241(b)**	x			
	(f)	Nondestructive testing – the operator must retain, for the life of the pipeline, a record showing by mile post, engineering station, or by geographic feature, the number of welds nondestructively tested, the number of welds rejected, and the disposition of the rejected welds.	x			

Comments:

.273(b)		JOINING of PIPELINE MATERIALS **(Notes: The unit does not have plastic pipe.)**	S	U	N/A	N/C
	.281	Joining of plastic pipe				
		• Type of plastic used			x	
		• Proper markings in accordance with **§192.63**			x	
		• Manufacturer			x	
		• Type of joint used			x	
*	.283	Qualified joining procedures for plastic pipe must be in place. Amdt. 192-103 pub. 06/09/06, eff. 07/10/06.			x	
	.285	Persons making joints with plastic pipe must be qualified			x	
	.287	Persons inspecting plastic joints must be qualified			x	

Comments:

.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.453	Are corrosion procedures established and carried out by or under the direction of a qualified person for:				
		• Design	x			
		• Operations	x			
		• Installation	x			

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.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
		• Maintenance	x			
	.455	(a) For pipelines installed **after July 31, 1971**, buried segments must be externally coated and (b) cathodically protected within **one year** after construction (see exceptions in code)	x			
		(c) Aluminum may not be installed in a buried or submerged pipeline if exposed to an environment with a natural **pH in excess of 8** (see exceptions in code) **(Notes: There is no aluminum in the system.)**			x	
	.457	(a) All effectively coated steel transmission pipelines installed prior to **August 1, 1971**, must be cathodically protected **(Notes: The line was installed in 1992. It has CP.)**			x	
		(b) If installed **before August 1, 1971**, cathodic protection must be provided in areas of active corrosion for: bare or ineffectively coated transmission lines, and bare or coated c/s, regulator sta. and meter sta. piping. **(Notes: The line was installed in 1992. It has CP.)**			x	
	.459	Examination of buried pipeline when exposed: if corrosion is found, further investigation is required	x			
	.461	Procedures must address the protective coating requirements of the regulations. External coating on the steel pipe must meet the requirements of this part.	x			
	.463	Cathodic protection level according to **Appendix D** criteria	x			
	.465	(a) Pipe-to-soil monitoring (**1 per yr/15 months**) or short sections (**10% per year, all in 10 years**)	x			
		(b) Rectifier monitoring (**6 per yr/2½ months**)	x			
		(c) Interference bond monitoring (**as required**)	x			
		(d) Prompt remedial action to correct any deficiencies indicated by the monitoring	x			
	.465	(e) Electrical surveys (closely spaced pipe to soil) on bare/unprotected lines, cathodically protect active corrosion areas (**1 per 3 years/39 months**). **(Notes: There are no bare/unprotected lines and no active corrosion areas.)**			x	
	.467	Electrical isolation (**include casings**)	x			
	.469	Sufficient test stations to determine CP adequacy	x			
	.471	Test leads	x			
	.473	Interference currents	x			
	.475	(a) Proper procedures for transporting corrosive gas? **(Notes: The gas transported is non-corrosive.)**			x	
* *		(b) Removed pipe must be inspected for internal corrosion. If found, the adjacent pipe must be inspected to determine extent. Certain pipe must be replaced. Steps must be taken to minimize internal corrosion.	x			
*	.476	Systems designed to reduce internal corrosion Final Rule Pub. (a) New construction Final Rule Pub. 4/23/07, eff. 5/23/07. **(Notes: This requirement was not in the O&M manual during the inspection. It was revised to include this requirement immediately following the inspection.)**		x		
		(b) Exceptions – offshore pipeline and systems replaced before 5/23/07. Final Rule Pub. 4/23/07, eff. 5/23/07. **(Notes: There are no offshore pipelines and systems replaced before 5/23/07.)**			x	
		(c) Evaluate impact of configuration changes to existing systems. Final Rule Pub. 4/23/07, eff. 5/23/07. **(Notes: There were no configuration changes to existing systems.)**			x	
	.477	Internal corrosion control coupon (or other suit. Means) monitoring (**2 per yr/7½ months**) **(Notes: There were no internal corrosion control coupons in the system.)**			x	
	.479	(a) Each exposed pipe must be cleaned and coated (see exceptions under .479(c))	x			
		Offshore splash zones and soil-to-air interfaces must be coated **(Notes: There are no offshore pipelines.)**			x	
		(b) Coating material must be suitable	x			
		Coating is not required where operator has proven that corrosion will: **(Notes: Coating is required for this unit.)**				
		(c) (1) Only be a light surface oxide, or			x	
		(2) Not affect safe operation before next scheduled inspection			x	
	.481	(a) Atmospheric corrosion control monitoring (**1 per 3 yrs/39 months onshore; 1 per yr/15 months offshore**)	x			
	.481	(b) Special attention required at soil/air interfaces, thermal insulation, under disbonded coating, pipe supports, splash zones, deck penetrations, spans over water.	x			
	.481	(c) Protection must be provided if atmospheric corrosion is found (**per §192.479**).	x			

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.483	Replacement pipe must be coated and cathodically protected (see code for exceptions)	x			
	.485	(a) Procedures to replace pipe or reduce the **MAOP** if general corrosion has reduced the wall thickness?	x			
		(b) Procedures to replace/repair pipe or reduce **MAOP** if localized corrosion has reduced wall thickness (unless reliable engineering repair method exists)?	x			
		(c) Procedures to use **Rstreng** or **B-31G** to determine remaining wall strength?	x			
	.491	Corrosion control maps and record retention (**pipeline service life or 5 yrs**)	x			

Comments:

.605(b)		**UNDERWATER INSPECTION PROCEDURES – GULF of MEXICO and INLETS** If the operator has no pipelines in the Gulf, check here and skip this section X	S	U	N/A	N/C
	.612(a)	Operator must have a procedure prepared by August 10, 2005 to identify pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep that are at risk of being an exposed underwater pipeline or a hazard to navigation?			x	
	.612(b)	Operator must conduct appropriate periodic underwater inspections based on the identified risk			x	
	.612(c)	Do procedures require the operator to take action when the operator discovers that a pipeline is exposed on the seabed, or constitutes a hazard to navigation:			x	
		(1) Promptly, within **24 hours**, notify the **National Response Center** of the location of the pipeline?			x	
		(2) Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at the ends of the pipeline segment and at intervals of not over **500 yards long**, except that a pipeline **segment less than 200 yards long** need only be marked at the center?			x	
		(3) Place the pipeline so that the top of the pipe is **36 inches below the seabed for normal excavation** or **18 inches for rock excavation** within **6 months** of discovery or not later than **November 1** of the following year if the **6 month period** is later than **November 1** of the year the discovery is made? See code re: engineering alternatives, PHMSA notification.			x	

.801- .809	**Subpart N — Qualification of Pipeline Personnel Procedures**
	Operator Qualification Inspection – Use PHMSA Form # 15 as applicable

.901- .951	**Subpart O — Pipeline Integrity Management**
	This form does not cover Gas Pipeline Integrity Management Programs

Subparts A - C	**PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES**
	Drug & Alcohol Testing & Alcohol Misuse Prevention Program – Use PHMSA Form # 13, PHMSA Drug and Alcohol Program Check.

Comments:

	PIPELINE INSPECTION (Field)	S	U	N/A	N/C
.179	Valve Protection from Tampering or Damage	x			
.463	Cathodic Protection	x			

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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	PIPELINE INSPECTION (Field)	S	U	N/A	N/C
.465	Rectifiers	x			
.476	Systems designed to reduce internal corrosion	x			
.479	Pipeline Components Exposed to the Atmosphere	x			
.612 (c) (2)	Pipelines exposed on seabed (Gulf of Mexico and Inlets): Marking			x	
613(b), .703	Pipeline condition, unsatisfactory conditions, hazards, etc.	x			
.707	ROW Markers, Road and Railroad Crossings **(Notes: The telephone number on recently replaced markers was incorrect.)**		x		
.719	Pre-pressure Tested Pipe **(Markings and Inventory)**	x			
.739/.743	Pressure Limiting and Regulating Devices (spot-check field installed equipment vs. inspection records) **(Notes: The pressure relief valve is operated by Williams upstream of the KB Pipeline.)**			x	
.745	Valve Maintenance	x			
.751(c)	Warning Signs Posted	x			

Comments:

	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered") **(Notes: There are no compressor stations in this unit.)** If not located on a platform check here and skip 192.167(c) X	S	U	N/A	N/C
.163(c)	Main operating floor must have (at least) two (2) separate and unobstructed exits			x	
	Door latch must open from inside without a key			x	
	Doors must swing outward			x	
.163(d)	Each fence around a compressor station must have (at least) 2 gates or other facilities for emergency exit			x	
	Each gate located within 200 ft of any compressor plant building must open outward			x	
	When occupied, the door must be opened from the inside without a key			x	
.163(e)	Does the equipment and wiring within compressor stations conform to the **National Electric Code, ANSI/NFPA 70?**			x	
.165(a)	If applicable, are there liquid separator(s) on the intake to the compressors?			x	
.165(b)	Do the liquid separators have a manual means of removing liquids?			x	
	If slugs of liquid could be carried into the compressors, are there automatic dumps on the separators, Automatic compressor shutdown devices, or high liquid level alarms?			x	
.167(a)	ESD system must:				
	- Discharge blowdown gas to a safe location			x	
	- Block and blowdown the gas in the station			x	
	- Shut down gas compressing equipment, gas fires, electrical facilities in compressor building and near gas headers			x	
	- Maintain necessary electrical circuits for emergency lighting and circuits needed to protect equipment from damage			x	
	ESD system must be operable from at least two locations, each of which is:				
	- Outside the gas area of the station			x	
	- Not more than 500 feet from the limits of the station			x	
	- ESD switches near emergency exits?			x	
.167 (b)	For stations supplying gas directly to distribution systems, is the ESD system configured so that the LDC will not be shut down if the ESD is activated?			x	

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered") **(Notes: There are no compressor stations in this unit.)** If not located on a platform check here and skip 192.167(c) X		S	U	N/A	N/C
.167(c)	Are ESDs on platforms designed to actuate automatically by…				
	- For unattended compressor stations, when:				
	• The gas pressure equals MAOP plus 15%?			x	
	• An uncontrolled fire occurs on the platform?			x	
	- For compressor station in a building, when:				
	• An uncontrolled fire occurs in the building?			x	
	• Gas in air reaches 50% or more of LEL in a building with a source of ignition (facility conforming to **NEC Class 1, Group D** is not a source of ignition)?			x	
.171(a)	Does the compressor station have adequate fire protection facilities? If fire pumps are used, they must not be affected by the ESD system.			x	
(b)	Do the compressor station prime movers (other than electrical movers) have over-speed shutdown?			x	
(c)	Do the compressor units alarm or shutdown in the event of inadequate cooling or lubrication of the unit(s)?			x	
(d)	Are the gas compressor units equipped to automatically stop fuel flow and vent the engine if the engine is stopped for any reason?			x	
(e)	Are the mufflers equipped with vents to vent any trapped gas?			x	
.173	Is each compressor station building adequately ventilated?			x	
.457	Is all buried piping cathodically protected?			x	
.481	Atmospheric corrosion of aboveground facilities			x	
.603	Does the operator have procedures for the start-up and shut-down of the station and/or compressor units?			x	
	Are facility maps current/up-to-date?			x	
.615	Emergency Plan for the station on site?			x	
.707	Markers			x	
.731	Overpressure protection – reliefs or shutdowns			x	
.735	Are combustible materials in quantities exceeding normal daily usage, stored a safe distance from the compressor building?			x	
	Are aboveground oil or gasoline storage tanks protected in accordance with **NFPA standard No. 30?**			x	
.736	Gas detection – location			x	

Comments:

CONVERSION TO SERVICE PERFORMANCE and RECORDS If no service conversion, check here and skip the section X		S	U	N/A	N/C
.14 (a)(2)	Visual inspection of right of way, aboveground and selected underground segments			x	
(a)(3)	Correction of unsafe defects and conditions			x	
(a)(4)	Pipeline testing in accordance with Subpart J			x	
(b)	Pipeline records: investigations, tests, repairs, replacements, alterations (life of pipeline)			x	

REPORTING PERFORMANCE and RECORDS		S	U	N/A	N/C
191.5	Immediate Notice Reports to NRC. ~~(800-424-8802)~~ **(Notes: None during this inspection period.)**			x	
191.12	Mechanical Fitting Failure Report (DOT Form PHMSA 7100.1-2) - if a fitting failure happened in the previous year. **(Notes: None during this inspection period.)**			x	

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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REPORTING PERFORMANCE and RECORDS		S	U	N/A	N/C
191.15	Written incident reports; supplemental incident reports (DOT Form PHMSA F 7100.2) **(Notes: None during this inspection period.)**			x	
191.17 (a)	Annual Report (DOT Form PHMSA F 7100.2-1)	x			
191.23	Safety related condition reports **(Notes: None during this inspection period.)**			x	
191.27	Offshore pipeline condition reports **(Notes: There are no offshore pipelines in this unit.)**			x	
192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports **(Notes: None during this inspection period. There are no offshore pipelines in this unit.)**			x	

CONSTRUCTION PERFORMANCE and RECORDS **(Notes: There were no construction activities during this inspection period.)**		S	U	N/A	N/C
.225	Test Results to Qualify Welding Procedures	x			
.227	Welder Qualification	x			
.241 (a)	Visual Weld Inspector Training/Experience			x	
.243 (b)(2)	Nondestructive Technician Qualification			x	
(c)	NDT procedures			x	
(f)	Total Number of Girth Welds			x	
(f)	Number of Welds Inspected by NDT			x	
(f)	Number of Welds Rejected			x	
(f)	Disposition of each Weld Rejected			x	
.303	Construction Specifications			x	
.325	Underground Clearance			x	
.327	Amount, Location, Cover of each Size of Pipe Installed			x	
.328	If the pipeline will be operated at the alternative MAOP standard calculated under 192.620 (80% SMYS) refer to PHMSA Form 5 (Construction) for additional construction requirements			x	
.455	Cathodic Protection			x	

OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS			S	U	N/A	N/C
.10		**OUTER CONTINENTAL SHELF ONLY:** Operator has identified on pipeline(s) [or if subsea - on a schematic] the specific point(s) at which operating responsibility transfers to a producing operator.			x	
.16		Customer Notification (**Verification – 90 days – and Elements**)			x	
.603(b)	.605(a)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**)	x			
.603(b)	.605(c)	Abnormal Operations **(Notes: None during this inspection period.)**			x	
.603(b)	.605(b)(3)	Availability of construction records, maps, operating history to operating personnel **(Notes: None during this inspection period.)**			x	
.603(b)	.605(b)(8)	Periodic review of personnel work – effectiveness of normal O&M procedures	x			
.603(b)	.605(c)(4)	Periodic review of personnel work – effectiveness of abnormal operation procedures **(Notes: None during this inspection period.)**			x	
.709	.609	Class Location Study (**If Applicable**)	x			
.603(b)	.612(b)	Gulf of Mexico/inlets: Periodic underwater inspections based on the identified risk			x	
.709	.614	Damage Prevention (**Miscellaneous**)	x			
.603(b)	.615(b)(1)	Location Specific Emergency Plan	x			
.603(b)	.615(b)(2)	Emergency Procedure training, verify effectiveness of training	x			
.603(b)	.615(b)(3)	Employee Emergency activity review, determine if procedures were followed. **(Notes: None during this inspection period.)**			x	
.603(b)	.615(c)	Liaison Program with Public Officials	x			
.603(b)	.616	Public Awareness Program:				

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS			S	U	N/A	N/C
	.616(e & f)	Documentation properly and adequately reflects implementation of operator's Public Awareness Program requirements - Stakeholder Audience identification, message type and content, delivery method and frequency, supplemental enhancements, program evaluations, etc. (i.e. contact or mailing rosters, postage receipts, return receipts, audience contact documentation, etc. for emergency responder, public officials, school superintendents, program evaluations, etc.). See table below: **(Notes: A joint PHMSA/UTC inspection for operator's public awareness program was conducted in October 2011. This inspection did not repeat what has just been completed.)**				x

API RP 1162 Baseline Recommended Message Deliveries	
Stakeholder Audience (Natural Gas Transmission Line Operators)	
	Baseline Message Frequency (starting from effective date of Plan)
Residents Along Right-of-Way and Places of Congregation	2 years
Emergency Officials	Annual
Public Officials	3 years
Excavator and Contractors	Annual
One-Call Centers	As required of One-Call Center
Stakeholder Audience (Gathering Line Operators)	**Baseline Message Frequency**
Residents and Places of Congregation	2 Years
Emergency Officials	Annual
Public Officials	3 years
Excavators and Contractors	Annual
One-Call Centers	As required of One-Call Center
Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.	

			S	U	N/A	N/C
	.616(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area.	x			
	.616(h)	Effectiveness Review of operator's program.				x
.517		Pressure Testing			x	
.553(b)		Uprating - as prescribed by .555, or .557 as applicable.			x	
.709	.619 / .620	Maximum Allowable Operating Pressure (**MAOP**) If the pipeline is operating at the alternative MAOP under 192.620 (80% SMYS), refer to Attachment 1 for additional requirements.			x	
.709	.625	Odorization of Gas	x			
.709	.705	Patrolling (**Refer to Table Below**)	x			

Class Location	At Highway and Railroad Crossings	At All Other Places
1 and 2	**2/yr (7½ months)**	**1/yr (15 months)**
3	**4/yr (4½ months)**	**2/yr (7½ months)**
4	**4/yr (4½ months)**	**4/yr (4½ months)**

			S	U	N/A	N/C
.709	.706	Leak Surveys (**Refer to Table Below**)	x			

Class Location	Required	Not Exceed
1 and 2	**1/yr**	**15 months**
3	**2/yr***	**7½ months**
4	**4/yr***	**4½ months**

* Leak **detector equipment** survey required for lines transporting un-odorized gas.

			S	U	N/A	N/C
.709	.731(a)	Compressor Station Relief Devices (**1 per yr/15 months**) **(Notes: There are no compressor stations in this unit.)**			x	
.709	.731(c)	Compressor Station Emergency Shutdown (**1 per yr/15 months**)			x	
.709	.736(c)	Compressor Stations – Detection and Alarms (**Performance Test**)			x	

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OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS			S	U	N/A	N/C
.709	.739	Pressure Limiting and Regulating Stations **(1 per yr/15 months)**			x	
.709	.743	Pressure Limiting and Regulator Stations – Capacity **(1 per yr/15 months)**			x	
.709	.745	Valve Maintenance **(1 per yr/15 months)**	x			
.709	.749	Vault Maintenance **(≥ 200 cubic feet)(1 per yr/15 months)**			x	
.603(b)	.751	Prevention of Accidental Ignition (hot work permits)	x			
.603(b)	.225(b)	Welding – Procedure	x			
.603(b)	.227/.229	Welding – Welder Qualification	x			
.603(b)	.243(b)(2)	NDT – NDT Personnel Qualification	x			
.709	.243(f)	NDT Records **(Pipeline Life)**	x			
.709	Repair: pipe **(Pipeline Life)**; Other than pipe **(5 years)**		x			
.807(b)	Refer to PHMSA Form # 15 to document review of operator's employee covered task records.					

Comments:

CORROSION CONTROL PERFORMANCE and RECORDS			S	U	N/A	N/C
.453	CP procedures (system design, installation, operation, and maintenance) must be carried out by qualified personnel		x			
.491	.491(a)	Maps or Records	x			
.491	.459	Examination of Buried Pipe when Exposed	x			
.491	.465(a)	Annual Pipe-to-soil Monitoring **(1 per yr/15 months)** or short sections **(10 % per year, all in 10 years)**	x			
.491	.465(b)	Rectifier Monitoring **(6 per yr/2½ months)**	x			
.491	.465(c)	Interference Bond Monitoring – Critical **(6 per yr/2½ months)** **<u>(Notes: There are no interference bonds.)</u>**			x	
.491	.465(c)	Interference Bond Monitoring – Non-critical **(1 per yr/15 months)** **<u>(Notes: There are no interference bonds.)</u>**			x	
.491	.465(d)	Prompt Remedial Actions	x			
.491	.465(e)	Unprotected Pipeline Surveys, CP active corrosion areas **(1 per 3 cal yr/39 months)** **<u>(Notes: There are no unprotected pipelines or CP active corrosion areas in this system.)</u>**			x	
.491	.467	Electrical Isolation **(Including Casings)**	x			
.491	.469	Test Stations – Sufficient Number	x			
.491	.471	Test Leads	x			
.491	.473	Interference Currents **<u>(Notes: There are no interference currents for the pipeline section within Washington State.)</u>**			x	
.491	.475(a)	Internal Corrosion; Corrosive Gas Investigation	x			
.491	.475(b)	Internal Corrosion; Internal Surface Inspection; Pipe Replacement	x			
.491	.476 (c)	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems **<u>(notes: There was no new system design during this inspection period.)</u>**			x	
.491	.477	Internal Corrosion Control Coupon Monitoring **(2 per yr/7½ months)** **<u>(Notes: There were no coupons.)</u>**			x	
.491	.481	Atmospheric Corrosion Control Monitoring **(1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore)**	x			
.491	.483/.485	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions	x			

Comments:

Comments:

Attachment 1
Alternative Maximum Allowable Operating Pressure

For additional guidance refer to http://primis.phmsa.dot.gov/maop/faqs.htm
For FAQs refer to http://primis.phmsa.dot.gov/maop/faqs.htm

(Notes: The operator does not use Alternative MAOP for the pipeline system.)

192.620		Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
		The alternative MAOP is calculated by using different factors in the same formulas used for calculating MAOP in §192.619. In determining the alternative design pressure under §192.105 use a design factor determined in accordance with §192.111(b), (c), or (d), or, if none of these apply in accordance with: Class Location — Alternative Design Factor (F) 1 — 0.80 2 — 0.67 3 — 0.56				
.620(a)	(1)	Establish alternative MAOP commensurate with class location – no class 4			x	
	(2)	MAOP cannot exceed the lowest of the following:				
		(i) Design pressure of the weakest element			x	
		(ii) Test pressure divided by applicable factor			x	
.620(b)	(2)	Pipeline constructed of steel pipe meeting additional requirements in §192.112.			x	
	(3)	SCADA system with remote monitoring and control			x	
	(4)	Additional construction requirements described in §192.328			x	
	(5)	No mechanical couplings			x	
	(6)	No failures indicative of systemic material fault – if previously operated at lower MAOP			x	
	(7)	95% of girth welds have NDT			x	
.620(c)	(1)	PHMSA notified 180 days before operating at alternative MAOP			x	
	(2)	Senior Executive signatures and copy to PHMSA			x	
	(4)	Strength test per §192.505 or certify previous strength test			x	
	(6)	Construction tasks treated as covered tasks for Operator Qualification			x	
	(7)	Records maintained for life of system			x	
	(8)	Class location change anomaly remediations			x	
.620(d)	(1)	Threat matrix developed consistent with §192.917			x	
	(2)	Recalculate the potential impact circle per §192.903 and implement public education per §192.616			x	
	(3)	Responding to an emergency in an HCA:				
		(i) Identify HCAs using larger impact circle			x	
		(ii) Check personnel response times			x	
		(iii) Verify remote valve abilities			x	
		(iv) Verify line break valve control system			x	
	(4)	Protect the right-of-way:				
		(i) ROW patrols 12 per year not to exceed 45 days			x	
		(ii) Plan to identify and mitigate unstable soil			x	
		(iii) Replace loss of cover if needed			x	
		(iv) Use line-of-sight markers per §192.707			x	
		(v) Review damage prevention program in light of national consensus practices			x	
		(vi) ROW management plan to protect against excavation activities			x	
	(5)	Control Internal Corrosion:				
		(i) Program to monitor gas constituents			x	

192.620	Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
	(ii) Filter separators if needed			x	
	(iii) Gas Monitoring equipment used			x	
	(iv) Cleaning pigs, inhibitors, and sample accumulated liquids			x	
.620(d)	(v) Limit CO2, H2S, and water in the gas stream			x	
	(vi) Quarterly program review based on monitoring results			x	
	(6) (i) Control interference that can impact external corrosion			x	
	(ii) Survey to address interference currents and remedial actions			x	
	(7) Confirm external corrosion control through indirect assessment:				
	(i) Assess adequacy of CIS and perform DCVG or ACVG within 6 months			x	
	(ii) Remediate damage with IR drop > 35%			x	
	(iii) Integrate internal inspection results with indirect assessment			x	
	(iv) Periodic assessments for HCAs:				
	(A-C) Close interval surveys, test stations at ½ mile intervals, and integrate results			x	
	(8) Cathodic Protection:				
	(i) Complete remediations within 6 months of failed reading			x	
	(ii) Confirm restoration by a close interval survey			x	
	(iii) Cathodic protection system operational within 12 months of construction completion			x	
	(9) Baseline assessment of integrity:				
	(i)(A) Geometry tool run within 6 months of service			x	
	(i)(B) High resolution MFL tool run within 3 years of service			x	
	(ii) Geometry and MFL tool 2 years prior to raising pressure for existing lines			x	
	(iii) If short portions cannot accommodate tools, use direct assessment per §192.925, 927, 929 or pressure testing			x	
	(10) Periodic integrity assessments:				
	(i) Frequency for assessments determined as if all segments covered by Subpart O			x	
	(ii) Inspect using MFL tool or direct assessment per §192.925, 927, 929 or pressure testing.			x	
	(11) Repairs:				
	(i)(A) Use of the most conservative calculation for anomaly remaining strength			x	
	(B) Tool tolerances taken into consideration			x	
	(ii) Immediate repairs for:				
	(A) Dents meeting 309(b) criteria			x	
	(B) Defects meeting immediate criteria in §192.933(d)			x	
	(C) Calculated failure pressure ratio less than 1.25 for .67 design factor			x	
	(D) Calculated failure pressure ratio less than 1.4 for .56 design factor			x	
	(iii) Repairs within 1 year for:				
	(A) Defects meeting 1 year criteria in 933(d)			x	
	(B) Calculated failure pressure ratio less than 1.25 for .80 design factor			x	
	(C) Calculated failure pressure ratio less than 1.50 for .67 design factor			x	
	(D) Calculated failure pressure ratio less than 1.80 for .56 design factor			x	
	(iv) Evaluate defect growth rate for anomalies with > 1 year repair interval and set repair interval			x	
.620(e)	(1) Provide overpressure protection to a max of 104% MAOP			x	
	(2) Procedure for establishing and maintaining set points for SCADA			x	

Comments:

Comments:

Leave this list with the operator.

All PHMSA Advisory Bulletins (Last 2 years)

Number	**Date**	**Subject**
ADB-09-01	May 21, 2009	Pipeline Safety: Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe
ADB-09-02	September 30, 2009	Pipeline Safety: Weldable Compression Coupling Installation
ADB-09-03	December 7, 2009	Pipeline Safety: Operator Qualification (OQ) Program Modifications
ADB-09-04	January 19, 2010	Pipeline Safety: Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-10-01	January 26, 2010	Pipeline Safety: Leak Detection on Hazardous Liquid Pipelines
ADB-10-02	February 3, 2010	Pipeline Safety - Implementation of Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-03	March 24, 2010	Pipeline Safety: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe
ADB-10-04	April 29, 2010	Pipeline Safety: Implementation of Electronic Filing for Recently Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems
ADB-10-05	June 28, 2010	Pipeline Safety: Updating Facility Response Plans in Light of Deepwater Horizon Oil Spill
ADB-10-06	August 3, 2010	Pipeline Safety: Personal Electronic Device Related Distractions
ADB-10-07	August 31, 2010	Liquefied Natural Gas Facilities: Obtaining Approval of Alternative Vapor-Gas Dispersion Models
ADB-10-08	November 3, 2010	Pipeline Safety: Emergency Preparedness Communications
ADB-11-01	January 4, 2011	Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation
ADB-11-02	February 9, 2011	Dangers of Abnormal Snow and Ice Build-up on Gas Distribution Systems

For more PHMSA Advisory Bulletins, go to http://phmsa.dot.gov/pipeline/regs/advisory-bulletin

PHMSA Pipeline Drug & Alcohol Questions

Instructions

1. Use in conjunction with Unit inspections
2. Interview the primary operator contact for the Unit inspection you are conducting and enter their responses. Do not request the operator substance abuse expert to provide responses to these questions.
3. Send completed form to stanley.kastanas@dot.gov

Name of Operator	KB Pipeline	**Op ID #**	31522
Inspector	Kuang Chu, Dennis Ritter/UTC	**Unit #**	9775
Date of Inspection	11-09-2011		
Inspection Location City & State	Beaver Power Plant, Clatskanie, OR		
Operator Employee Interviewed	Bob Cosentino/Charissa Norton	**Phone #**	530-604-3868
Position/Title	Consultant/PGE Drug &Alcohol Program Assistant		
Operator Designated Employer Representative (DER), (a.k.a. Substance Abuse Program Manager)	**DER-Linda Keezer; Drug & Alcohol Program Asst-Charissa Norton; EAP Robin Waterman**		
DER Phone #	**503-464-7269/503-464-8492**		

§199	Pipeline Safety Regulations Drug and Alcohol Testing	Yes	No	Does Not Know
.3, .101 .201, .245	**1. Does the company have a plan for drug and alcohol testing of employees and contractors performing, or ready to perform, covered functions of operations, maintenance, and emergency response?**	X		
Comments	The random testing is set up for all identified employees involved with PGE pipelines (includes several power plants in Oregon including the K-B pipeline). Total in pool is 78.			
.3 .105(c) .225(b)	**2. Does the company perform random drug testing and reasonable suspicion drug and alcohol testing of employees performing covered functions? For random drug testing, enter the number of times per year employees are selected and the number of employees in each selection in Comments below.**	X		
Comments	78 members in pipeline pool; 25% of pool each year is tested for a total of 20 annually.			
.3 .105(b)	**3. Does the company conduct post-accident/incident drug and alcohol testing for employees who have caused or contributed to the consequences of an accident/incident? Enter the position/title of the employee who would make the decision to conduct post-accident/incident testing in Comments below.**	X		
Comments	The manager/supervisor with the help of the Human Resources Consultant/DER/Drug & Alcohol Assistant can all make decisions to do post-accident/incident testing. PGE has a flow chart that determines if the testing is needed based on the circumstances of the accident/incident. Alcohol testing must be done as soon as possible, but within 8 hours, drug testing within 32 hours.			
.113(c) .117(a)(4) .227(b)(2) .241	**4. Does the company provide training for supervisors on the detection of potential drug abuse (minimum 60 minutes) and alcohol misuse (minimum 60 minutes)?**	X		
Comments	At hire into supervisory position.			
.3 .113(b) .117(a)(4) .239(b)(11)	**5. Does the company give covered employees an explanation of the drug & alcohol policies and distribute information about the Employee Assistance Program, including a hotline number? Provide details in Comments below.**	X		
Comments	Employees are given information on the Employee Assistance Program (EAP) when hired. There are EAP posters and brochures available (confirmed on site at Beaver) with contact information. Employees are also given a packet with a DOT Drug and Alcohol booklet, Corporate Drug and Alcohol Policy, highlights of Drug and Alcohol testing program and DOT Drug and Alcohol testing contact information when they are hired.			

OPERATOR QUALIFICATION
FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	November 9, 2011
Name of Operator:	KB Pipeline
Operator ID (OPID):	31522
Inspection Location(s):	Cowlitz County, Washington
Supervisor(s) Contacted:	Robert Cosentino
# Qualified Employees Observed:	None
# Qualified Contractors Observed:	One

Individual Observed	Title/Organization	Phone Number	Email Address
Vic Meder	Contracted Operator	360-430-2825	

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Kuang Chu & Dennis Ritter/UTC	Western/WA	kchu@utc.wa.gov dritter@utc.wa.gov

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is on the last page of this form. This form is to be uploaded on to the OQBD for the appropriate operator, then imported into the file.

9.01 Covered Task Performance

Verify the qualified individuals performed the observed covered tasks in accordance with the operator's procedures or operator approved contractor procedures.

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.02 Qualification Status

Verify the individuals performing the observed covered tasks are currently qualified to perform the covered tasks.

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.03 Abnormal Operating Condition Recognition and Reaction

Verify the individuals performing covered tasks are cognizant of the AOCs that are applicable to the tasks observed.

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.04 Verification of Qualification

Verify the qualification records are current, and ensure the personal identification of all individuals performing covered tasks are checked, prior to task performance.

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected at the operational level?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
x	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Field Inspection Notes

The following table is provided for recording the covered tasks observed and the individuals performing those tasks.

		Name/ID of Individual Observed			
		Vic Meder			
No	Task Name	Correct Performance (Y/N)	Correct Performance (Y/N)	Correct Performance (Y/N)	Comments
1	CP Systems Testing Steps	Y			
2	CP Systems Electrical Connections	Y			
3	Valve maintenance	Y			
4					
5					
6					
7					
8					

. Operations and Maintenance Records Review

If performing an operations and maintenance records review in the course of your inspection, please review a sample of the qualifications of the individuals performing those O&M tasks that are covered under Operator Qualification and check the records for compliance to 192.807 or 195.507.

		Sat.	Unsat.	Not Checked
192.807 or 195.507	Records supporting an individual's current qualifications shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.	x		
	Comments:			

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

1. Pipeline Safety Advisory Bulletin - ADB-03-05 - October 8, 2003
   - Review Bulletin with operator, if operator is not familiar with.
   - Reference also Baker Stress Corrosion Cracking Study at: http://primis.phmsa.dot.gov/gasimp/docs/SCC_Report-Final_Report_with_Database.pdf

Comments: KB Pipeline has reviewed ADB-03-05 and does not consider itself to be susceptible to SCC based on the risk factors as listed after question 10 on this questionnaire.

2. Has the pipeline system ever experienced SCC (in service, out of service, leak, non-leak)?
   - Type of SCC?
     Classical - high pH
     Non-classical – low or near neutral pH
   - What are the known risk indicators that may have contributed to the SCC?

Comments: No

3. Does the operator have a written program in place to evaluate the pipeline system for the presence of SCC? If no, have operator explain. If operator has not considered SCC as a possible safety risk, go to #10.

Comments: No plan in place specific to SCC beyond required inspections for internal and external corrosion. Absence of a specific plan is based on not meeting the risk factors as listed after question 10 on this questionnaire.

4. Has/does the operator evaluate the pipeline system for the presence of SCC risk indicators?

Comments: Yes.

5. Has the operator identified pipeline segments that are susceptible to SCC?

Comments: The entire pipeline is not susceptible to SCC.

6. If conditions for SCC are present, are written inspection, examination and evaluation procedures in place?

Comments: N/A

7. Does the operator have written remediation measures in place for addressing SCC when discovered?

Comments: No.

8. What preventive measures has the operator taken to prevent recurrence of SCC?
    - Modeling?
        - Crack growth rate?
        - Comparing pipe/environ./cp data vs. established factors?
        - Other?
    - Hydrotest program?
    - Intelligent pigging program?
    - Pipe re-coating?
    - Operational changes?
    - Inspection program?
    - Other?

Comments: None.

9. Does the operator incorporate the risk assessment of SCC into a comprehensive risk management program?

Comments: KB caries internal and external inspection whenever pipe becomes available to inspect. Latest anomaly investigations have incorporated magnetic particle inspection as part of the evaluation. No indication of SCC has been found.

Continue below for those operators who have not considered SCC as a possible safety risk.

10. Does the operator know of pipeline and right of way conditions that would match the risk indicators for either classical or non-classical SCC? See typical risk indicators below.

SUPPLEMENTAL SCC QUESTIONNAIRE
GAS TRANSMISSION OR LIQUID PIPELINE

Comments: KB Pipeline is aware of the risk factors listed below and does not consider itself a risk to SCC based on the following; 1. No history of SCC 2. Use of FBE coating 3. Pipe temperature less than 100 deg. F (no compression) 4. Polarized potential outside of the indicated rage

High pH SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
    - Age ≥ 10 years
    - Operating stress > 60% SMYS
    - Pipe temperature >100 deg. F (typically < 20 miles d/s of compression)
    - Damaged pipe coating
- Soil Characteristics
    - Soil pH range: 8.5 to 11
    - Alkaline carbonate/bicarbonate solution in the soil
    - Elevated soil temperature contributing to elevated pipe temperature
- Polarized cathodic potential range: -600 to -750 mV, $Cu/CuSO_4$

Low or Near-Neutral pH SCC Potential Risk Indicators

- Known SCC history (failure, non-failure, in service, and during testing)
- Pipeline and Coating Characteristics
- Steel grades X-52, X-60, X-65, X-70, and possibly X-42
    - Age ≥ 10 years
    - Frequently associated with metallurgical features, such as mechanical damage, longitudinal seams, etc.
    - Protective coatings that may be susceptible to disbondment
        - Any coating **other than** correctly applied fusion bonded epoxy, field applied epoxies, or coal tar urethane . . .
        - Coal tar
        - Asphalt enamels
        - Tapes
        - Others
- Soil Characteristics
    - Soil pH range: 4 to 8

- Dissolved CO_2 and carbonate chemicals present in soil
- Organic decay
- Soil leaching (in rice fields, for example)

• "Normal" cathodic protection readings (disbonded coating shields the pipe from cp current)

Field Data Collection
(2011 Standard Inspection)

Company: KB Pipeline

Unit: KB Pipeline

Pipe-to-Soil Potential Readings, Rectifiers and Others

Date	Location	Pipe (Volts) Power On	Casing (Volts)	Comments
11/9/2011	**Hazel Dell Road Slide Area**			A 1" gap has been developed between bottom of the pipe and the steel pipe support beam for support #4, indicating that the ground has moved downward since the last inspection in March 2009.
11/9/2011	**Meter Station** 20" line downstream of the pig launcher at the station	-1.643		The station has good security and adequate signs. The odorant tank was leaking and needed to be repaired..
11/9/2011	**Mainline Valve Station for KBV-2** CP test station	-1.223		This mainline valve was partially operated by the operator Vic Meder and it was in good working condition.
11/9/2011	**Rectifier** (The only one on Washington State side of the pipeline) CP test station	-2.058		Rectifier DC output: 4.82 V; 1.92 A.
11/9/2011	**Mainline Valve Station for KBV-3** CP test station	-1.703		The valve station has its own security fence with lock and is inside gated Weyerhaeuser property. It is secured.
11/9/2011	**I-5 Freeway Crossing** CP test station	-1.836	-0.564	The casing was not shorted.

Western Region Unit Information

Inspector or State Office:	Kuang Chu & Dennis Ritter/UTC	SMART Activity #	
Unit ID:	9775	Unit Name:	KB Pipeline
Operator ID:	31522	Operator Name:	KB Pipeline

Unit Boundaries

Description:	Device:	Latitude:	Longitude:
The Kelso-Beaver (KB) Pipeline is located in Cowlitz County, Washington. The KB Pipeline takes delivery of natural gas from the Williams Northwest Pipeline meter station located east of Kelso, Washington and extends west approximately 18 miles to Columbia County, Oregon. The pipeline crosses under the Columbia River north of the City of Longview, WA. The pipeline is a 20" API 5L grade X-52 with 0.281", 0.344" & 0.375" thickness			

Pre-Inspection

The information collected and documented here is in addition to other pre-inspection efforts [pulling unit summaries, SRCR's, Annual Reports, Accident/Incident Reports, previous PIM, Post-Inspection OQ & IMP reports, previous and outstanding enforcement actions, etc.]

There are no HCAs for this pipeline. Therefore, the gas IMP does not apply to this pipeline. An ILI run was made in early 2011 with a high resolution MFL tool and a geometry tool. Two (?) anomaly digs were made in 2011 to direct examine the anomalies following the ILI run. A leak was discovered in late 2010 and was repaired. The leak was apparently caused by a construction worker's deliberated act during the original construction of the pipeline.

Baseline Information

1) If accidents or incidents have occurred in this unit, what has the operator done to prevent recurrence? *(select all that apply)*

- ☐ Added Equipment
- ☐ Procedural Change
- ☐ Engineering Barriers Added
- ☐ Removed Equipment
- ☐ Additional Training
- ☐ Other

Describe: N/A

2) Will these actions adequately mitigate threats? ○ Yes ○ No

Please Explain: N/A

3) Have any abnormal events occurred in this unit? ◉ Yes ○ No

Describe Operator's Response: The gas leak was detected by a GPS crew and was repaired in a timely manner.

4) Commodity Transported:

Liquid 1:		Gas 1:	Natural Gas
Liquid 2:		Gas 2:	

5) Year of Original Installation (yyyy): 1992 Pipe specification (e.g. API 5L, ASTM D2513) API 5L X-52

6) Normal Operating Pressure (psig), min: 500 max: 809 % SMYS, max: 71

7) MOP/MAOP (psig), min: 500 max: 823 Changes in MOP/MAOP in previous year: ○ Increase ○ Decrease ◉ None

8) Seam Type: ERW

9) Coating Type: FBE

10) Overall Coating Quality: ( ) Poor ( ) Fair (•) Good Coating Improvement Efforts: ( ) Yes ( ) No

Describe:

11) Potential for AC Interference? (•) Yes ( ) No Has operator tested for stray current? (•) Yes ( ) No

12) Parallel Construction/Crossing? (•) Yes ( ) No Explain: No parallel, crosses Olympic Pipeline

13a) [Gas Only] Is there a monitoring program for liquids? ( ) Yes (•) No

Method:

Frequency:

13b) [Liquid Only] Are there Dead Legs? ( ) Yes ( ) No

Explain:

14) [Liquid Only] Number of cycles: per ( ) Day ( ) Week ( ) Month

Pressure range (psig):

15) Has equipment been deleted/added that changed the hydraulic profile of this line? ( ) Yes (•) No

Explain:

16) Level of automation: (•) Manual Control ( ) Local/SCADA ( ) Remote/SCADA

17) Total unit mileage: 19 miles

18) HCA-Affecting Mileage (% of total mileage):

High Population Area (%):	
Other Population Area (%):	
Drinking Water USA (%):	
Ecological Resource USA (%):	
Commercially Navigable Waterway (%):	<1% under Columbia River

19) Indicate the year of the most recent tool run and summarize results, including digs:

Tool Type	Year	Results Summary
Geometry	2010	Low Resolution, no anomaly found
Combination Tool	2010	High Resolution, anomalies noted, direct examined (digs)

Post-Inspection Information

20) Using your engineering judgement, describe how well is the manager addressing this unit's threats:

Corrosion Specific:	( ) Poor	( ) Fair	(•) Good
Equipment Specific:	( ) Poor	( ) Fair	(•) Good
Excavation Specific:	( ) Poor	( ) Fair	(•) Good
Human Error Specific:	( ) Poor	( ) Fair	(•) Good
Material/Weld Specific:	( ) Poor	( ) Fair	(•) Good
Natural Force Specific:	( ) Poor	( ) Fair	(•) Good
Overall:	( ) Poor	( ) Fair	(•) Good

Additional Assessments: We still have a concern about the pipeline integrity at the Hazel Dell Road Slide Area. The ground at this area is unstable. The operator is monitoring the land movement by surveying the area periodically.