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.**

Notes: The 2008 Abbreviated Western Region form was used at the start of this inspection. The same day we received the updated 2009 edition of the standard inspection form. To be current, we decided to switch to the newly revised form the inspection to complete the inspection.

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	Kuang Chu/ 4/06/2009	**Inspector/Submit Date:**	Kuang Chu 4/06/2009
		Sr Eng Review/Date:	D. Lykken 4/07/2009
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Cascade Natural Gas	**OPID #:**	31522
Name of Unit(s):	Kelso-Beaver Pipeline	**Unit #(s):**	9775
Records Location:	Longview, WA		
Unit Type & Commodity:	Interstate Natural Gas Transmission		
Inspection Type:	I01 Unit Inspection	**Inspection Date(s):**	March 23-March 25, 2009
PHMSA Representative(s):	Kuang Chu/UTC Staff	**AFO Days:**	3

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 PGE and is operated by Cascade Natural Gas. This inspection included a review of the records at Cascade Natural Gas' Longview, WA office and a field inspection of the pipeline from the gate station located at the delivery point from Williams Pipeline West located northeast of Longview, WA to the valve station KBV-02. 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 were no probable violations found during this inspection. All the issues raised during the previous inspection conducted in 2007 have either been resolved or clarified.

There are two KBV valves in this pipeline (KBV 2 & KBV 3). The defective bolts for these two valves will be replaced in April 2009.

The integrity of the pipeline at the "Hazel Dell Road Slide Area" is a great concern to us. The landslide is active in the "Flow Slide" area and there were signs of ground movement adjacent to the pipeline. 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 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 and it is holding the soil from sliding downward. New French drains were installed to improve drainage down-slope of the pipeline right after our field inspection. We recommend that the pipeline should be shut down and depressurized, and the section around the Flow Slide area be exposed to relieve pipe stress. PGE should consult with their geotechnical consultant to install French drains up-slope of the pipeline to minimize water from flowing into the area around the pipeline. Strain gages and piezometers should be installed to monitor pipe movement and ground water lever. The exposed pipe section may be re-buried. Alternatively, this exposed pipe section may be above ground with pile supports in lieu of strain gages.

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

Name of Operator: Cascade Natural Gas

OP ID No. (1) **31522**

Unit ID No. (1) **9775**

HQ Address:

Cascade Natural Gas
222 Fairview Ave. N
Seattle, WA 98109

System/Unit Name & Address: (1)

Kelso/Beaver c/o Cascade Natural Gas
1332 Vandercook Way
Longview, WA 98632

Co. Official: Mike Gardner, VP Operations
Phone No.: 206-381-6821
Fax No.:
Emergency Phone No.: 1-800-433-0252

Activity Record ID No.:
Phone No.: 360-600-1922
Fax No.: 360-751-4828
Emergency Phone No.: 1-800-433-0252

Persons Interviewed	Title	Phone No.
Sam Hicks	Compliance	206-381-6725
Tom Wilson	District Manager	509-952-5682
Dustin Knowles	Corrosion Technician	360-941-5986
Paul Gardner	Distribution Clerk	360-751-4828
Kathy Davies	Analyst (PGE)	503-464-7300

PHMSA Representative(s) (1) **Kuang Chu/UTC** **Inspection Date(s)** (1) **March 23-March 25, 2009**

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 two customers located in Oregon at the PGE's Beaver generating station and U.S. Gypsum near Rainier, Oregon.

Portion of Unit Inspected: (1)
This inspection included a review of the records at Cascade Natural Gas' Longview, WA office 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 rectifier at Eufaulla Road. Pipeline facilities inspected included the gate station, several cathodic protection test stations, road crossing casings, mainline valves, rectifier (only one in WA), above ground section of the pipeline, and land slide area.

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

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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 03/16/04 and 03/16/09.

49 CFR PART 191

	REPORTING PROCEDURES	S	U	N/A	N/C
.605(b)(4)	Procedures for gathering data for incident reporting				
	191.5 Telephonically reporting incidents to **NRC (800) 424-8802**				X
	191.15(a) 30-day follow-up written report (**Form 7100-2**)				X
	191.15(b) Supplemental report (to 30-day follow-up)				X
.605(a)	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				X
.605(d)	Instructions to enable operation and maintenance personnel to recognize potential **Safety Related Conditions**				X

Comments:
All the reporting procedures were reviewed during the Team O&M Review conducted in January 2007.

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. ***Notes: The K-B Pipeline is not for gas distribution systems.***			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
	.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				X
	.605(b)(11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency proced. under §192.615(a)(3) specifically apply to these reports.				X

Comments:

All the normal operating and maintenance procedures were reviewed during the team O&M manual review conducted in January 2007.

.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:
All the abnormal operating procedures were reviewed during the team O&M review conducted in January 2007.

.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:
These items were reviewed during the team O&M review conducted in January 2007.

.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:
These items were reviewed during the team O&M review conducted in January 2007.

.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

.605(a)	DAMAGE PREVENTION PROGRAM PROCEDURES	S	U	N/A	N/C
	(ii) After blasting, a leak survey must be conducted as part of the inspection by the operator				X

Comments:
The damage prevention program procedures were reviewed during the team O&M review conducted in January 2007.

.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				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
	.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(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				X

Comments:
The emergency procedures were reviewed during the team O&M review conducted in January 2007.

PUBLIC AWARENESS PROGRAM PROCEDURES (Also in accordance with API RP 1162)			S	U	N/A	N/C
.605(a) *	**.616**	Public Awareness Program also in accordance with API RP 1162. Amdt 192-99 pub. 5/19/05 eff. 06/20/05.				
	.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

		PUBLIC AWARENESS PROGRAM PROCEDURES **(Also in accordance with API RP 1162)**	S	U	N/A	N/C
	.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

Comments:
The public awareness program procedures were reviewed during the team O&M review conducted in January 2007.

.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:
The failure investigation procedures were reviewed during the team O&M review conducted in January 2007.

.605(a)		**MAOP PROCEDURES**	S	U	N/A	N/C
	Note: If the operator is operating at 80% SMYS with waivers, the inspector needs to review the special conditions of the waivers.					
	.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

.605(a)		**MAOP PROCEDURES**	S	U	N/A	N/C
*	.620	If the pipeline is designed to the alternative MAOP standard in 192.620 does it meet the additional design requirements for: • General standards • Fracture control • Plate and seam quality control • Mill hydrostatic testing • Coating • Fittings and flanges • Compressor stations Final Rule Pub. 10/17/08, eff. 12/22/08.				X

Comments:
The MAOP procedures were reviewed during the team O&M review conducted in January 2007.

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

Comments:
The pressure test procedures were reviewed during the team O&M review conducted in January 2007.

.13(c)	**UPRATING PROCEDURES**	S	U	N/A	N/C
	.553 Uprating				X

Comments:
The uprating procedures were reviewed during the team O&M review conducted in January 2007.

.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:
The odorization procedures were reviewed during the team O&M review conducted in January 2007.

.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:
These procedures were reviewed during the team O&M review conducted in January 2007.

.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:
The maintenance procedures were reviewed during the team O&M review conducted in January 2007.

.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:				

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)

						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
		(b) **Class 4** locations - **4½ months** but at least **4 times each calendar year**				X

Comments:
The transmission lines – patrolling & leakage survey procedures were reviewed during the team O&M review conducted in January 2007.

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

Comments:
The line marker procedures were reviewed during the team O&M review conducted in January 2007.

.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:
The record keeping procedures were reviewed during the team O&M review conducted in January 2007.

.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

.605(b)		**FIELD REPAIR PROCEDURES**	S	U	N/A	N/C
		(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
	(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				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				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:
The field repair procedures were reviewed during the team O&M review conducted in January 2007.

.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				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				X
		(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed				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:
The abandonment or deactivation of facilities procedures were reviewed during the team O&M review conducted in January 2007.

.605(b)		**COMPRESSOR STATION PROCEDURES**	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
	.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:
The K-B Pipeline does not have compressor stations. However, Cascade Natural Gas has compressor station procedures in their O&M manual.

<table>
<tr><th>.605(b)</th><th colspan="2">PRESSURE LIMITING and REGULATING STATION PROCEDURES</th><th>S</th><th>U</th><th>N/A</th><th>N/C</th></tr>
<tr><td></td><td>.739(a)</td><td>Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (1 per yr/15 months)</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td></td><td></td><td>(1) In good mechanical condition</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td></td><td></td><td>(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td>*</td><td>.739(a)</td><td>(3) Set to control or relieve at correct pressures consistent with .201(a), except for .739(b). Amdt. 192-96 pub. 5/17/04, eff.10/8/04</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td></td><td></td><td>(4) Properly installed and protected from dirt, liquids, other conditions that may prevent proper oper.</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td>*</td><td>.739(b)</td><td>For steel lines if MAOP is determined per .619(c) and the MAOP is 60 psi (414 kPa) gage or more . . . Amdt. 192-96 pub. 5/17/04, eff.10/8/04</td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td><table><tr><td>If MAOP produces hoop stress that</td><td>Then the pressure limit is:</td></tr><tr><td>Is greater than 72 percent of SMYS</td><td>MAOP plus 4 percent</td></tr><tr><td>Is unknown as a percent of SMYS</td><td>A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP</td></tr></table></td><td></td><td></td><td></td><td>X</td></tr>
<tr><td></td><td>.743</td><td>Testing of Relief Devices</td><td></td><td></td><td></td><td></td></tr>
<tr><td>*</td><td>.743</td><td>(a) Capacity must be consistent with .201(a) except for .739(b), and be determined 1 per yr/15 mo. Amdt. 192-96 pub. 5/17/04, eff.10/8/04</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td></td><td>.743</td><td>(b) If calculated, capacities must be compared; annual review and documentation are required.</td><td></td><td></td><td></td><td>X</td></tr>
<tr><td></td><td>.743</td><td>(c) If insufficient capacity, new or additional devices must be installed to provide required capacity.</td><td></td><td></td><td></td><td>X</td></tr>
</table>

Comments:
The pressure limiting and regulating station procedures were reviewed during the team O&M review conducted in January 2007.

.605(b)		VALVE AND VAULT MAINTENANCE PROCEDURES	S	U	N/A	N/C
		Valves				
	.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
		Vaults				
	.749	Inspection of vaults greater than **200 cubic feet (1 per yr/15 months)**				X

.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

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.

Comments:

These procedures were reviewed during the team O&M review conducted in January 2007.

.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** (19^{th} ed.1999, 10/31/01 errata) or **Section IX of ASME Boiler and Pressure Code** (2004 ed. Including addenda through July 1, 2005) by destructive test. Amdt.192-94 pub. 6/14/04, eff. 7/14/04; Amdt. 192-103 pub 06/09/06, eff. 07/10/06.				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** (19^{th} ed.1999, 10/31/01 errata) or **Section IX of ASME Boiler and Pressure Code** (2004 ed. Including addenda through July 1, 2005) See exception in .227(b). Amdt.192-94 pub. 6/14/04, eff. 7/14/04; Amdt. 192-103 pub 06/09/06, eff. 07/10/06; Amdt. 192-103 corr. Pub 02/01/07 eff. 03/05/07.				X
		(b)	Welders may be qualified under **section I of Appendix C** to weld on lines that operate at **< 20% SMYS.**				X
	.229	(a)	To weld on compressor station piping and components, a welder must successfully complete a destructive test				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. Amdt.192-94 pub. 6/14/04, eff. 7/14/04.				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).				X
		(d)	Welders qualified under .227(b) may not weld unless:				
		(1)	Requalified within **1 year/15 months**, or				X
		(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				X
*	.241	(a)	Visual inspection must be conducted by an individual qualified by appropriate training and experience to ensure: Amdt.192-94 pub. 6/14/04, eff. 7/14/04				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				X
		(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. Amdt.192-94 pub. 6/14/04, eff. 7/14/04				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				

.13(c)	WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES	S	U	N/A	N/C
	(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:
The welding and weld defect repair/removal procedures were reviewed during the team O&M review conducted in January 2007.

.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
		(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				
		(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:
The nondestructive testing procedures were reviewed during the team O&M review conducted in January 2007.

.273(b)			JOINING of PIPELINE MATERIALS	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.192-94 pub. 6/14/04, eff. 7/14/04; Amdt. 192-103 pub. 06/09/06, eff. 07/10/06.				X
	*	.285	Persons making joints with plastic pipe must be qualified Amdt.192-94 pub. 6/14/04, eff. 7/14/04				X
	*	.287	Persons inspecting plastic joints must be qualified Amdt.192-94 pub. 6/14/04, eff. 7/14/04				X

Comments: Although the K-B Pipeline is a steel pipeline, the operator has plastic materials for their gas distribution systems.

.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
		• 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)				X
	.457	(a) All effectively coated steel transmission pipelines installed prior to **August 1, 1971**, must be cathodically protected				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.				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**).				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?				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. 4/23/07, eff. 5/23/07. (a) New construction				X
		(b) Exceptions – offshore pipeline and systems replaced before 5/23/07				X
		(c) Evaluate impact of configuration changes to existing systems				X
	.477	Internal corrosion control coupon (or other suit. Means) monitoring (**2 per yr/7½ months**)				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				X
		(b) Coating material must be suitable				X
		Coating is not required where operator has proven that corrosion will:				
		(c) (1) Only be a light surface oxide, or				X
		(2) Not affect safe operation before next scheduled inspection				X

.605(b)		CORROSION CONTROL PROCEDURES	S	U	N/A	N/C
	.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
	.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:
The corrosion control procedures were reviewed during the team O&M review conducted in January 2007.

.605(b)		UNDERWATER INSPECTION PROCEDURES – GULF of MEXICO and INLETS	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? Amdt. 192-98 pub. 8/10/04, eff. 9/9/04			X	
*	.612(b)	Operator must conduct appropriate periodic underwater inspections based on the identified risk Amdt. 192-98 pub.8/10/04, eff. 9/9/04			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	S	U	N/A	N/C
	Refer to Operator Qualification Inspection Forms and Protocols (OPS web site)				

.901- .951	Subpart O — Pipeline Integrity Management	S	U	N/A	N/C
	This form does not cover Gas Pipeline Integrity Management Programs				

Subparts A - C	PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES	S	U	N/A	N/C
	Drug & Alcohol Testing & Alcohol Misuse Prevention Program – Use PHMSA Form # 13, PHMSA 2008 Drug and Alcohol Program Check.				

Comments:

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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

	PIPELINE INSPECTION (Field)	S	U	N/A	N/C
.179	Valve Protection from Tampering or Damage	X			
.463	Cathodic Protection	X			
.465	Rectifiers	X			
.476	Systems designed to reduce internal corrosion	X			
.479	Pipeline Components Exposed to the Atmosphere	X			
.605	Knowledge of Operating Personnel	X			
.612 (c) (2)	Pipelines exposed on seabed (Gulf of Mexico and Inlets): Marking ***Notes: The pipeline is not in Gulf of Mexico and Inlets.***			X	
613(b), .703	Pipeline condition, unsatisfactory conditions, hazards, etc. ***Notes: The integrity of the pipeline at the landslide area is a great concern to us. Please refer to the findings on the first page of this form and the PIM for details.***	X			
.707	ROW Markers, Road and Railroad Crossings	X			
.719	Pre-pressure Tested Pipe (**Markings and Inventory**) ***Notes: The operator does not keep pre-pressure tested pipe.***			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 K-B Pipeline.***				X
.745	Valve Maintenance	X			
.751	Warning Signs	X			
.801 - .809	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			

Comments:

	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")	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	
(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	
(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	
.167(c)	Are ESDs on platforms designed to actuate automatically by…				

	COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")	S	U	N/A	N/C
	- 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:
There are no compressor stations for this pipeline.

	CONVERSION TO SERVICE PERFORMANCE and RECORDS ***Notes: No conversion to service for this pipeline.***	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	Telephonic reports to NRC (800-424-8802) Notes: None during this inspection period.			X	
191.15	Written incident reports; supplemental incident reports (DOT Form RSPA F 7100.2) ***Notes: None during this inspection period.***			X	
191.17 (a)	Annual Report (DOT Form RSPA 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: The K-B Pipeline is onshore.***			X	
192.727 (g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports ***Notes: The K-B Pipeline is onshore.***			X	

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

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

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) does it meet the additional construction requirements for: Quality assurance, Girth welds, depth of cover, initial strength testing, and interference currents?			X	
.455	Cathodic Protection			X	

OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS			S	U	N/A	N/C
.16		Customer Notification (**Verification – 90 days – and Elements**) ***Notes: The K-B Pipeline is not for gas distribution systems.***			X	
.603(b)	.605(a)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**)	X			
.603(b)	.605(c)	Abnormal Operations ***Notes: There were no abnormal operations during this inspection period.***			X	
.603(b)	.605(b)(3)	Availability of construction records, maps, operating history to operating personnel	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	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 ***Notes: The K-B Pipeline is not in Gulf of Mexico/inlets.***			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.	X			
.603(b)	.615(c)	Liaison Program with Public Officials	X			
.603(b)	.616	Public Awareness Program				
	.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:	X			

API RP 1162 Baseline* Recommended Message Deliveries	
Stakeholder Audience (Natural Gas Transmission Line Operators)	
Residents Along Right-of-Way and Places of Congregation	**Baseline Message Frequency (starting from effective date of Plan)**
Emergency Officials	2 years
Public Officials	Annual
Excavator and Contractors	3 years
One-Call Centers	Annual
Stakeholder Audience (Gathering Line Operators)	As required of One-Call Center
Residents and Places of Congregation	**Baseline Message Frequency**

OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS	S	U	N/A	N/C

Emergency Officials	Annual
Public Officials	Annual
Excavators and Contractors	3 years
One-Call Centers	Annual
* Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.	As required of One-Call Center

			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. ***Notes: The primary population in the operator's area are English speaking people. There is no need to conduct the program in different languages.***	X			
.517		Pressure Testing	X			
.553(b)		Uprating ***Notes: No uprating conducted for this pipeline.***			X	
.709	.619 / .620	Maximum Allowable Operating Pressure (**MAOP**)	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.***			X	
.709	.731(c)	Compressor Station Emergency Shutdown (**1 per yr/15 months**) ***Notes: There are no compressor stations.***			X	
.709	.736(c)	Compressor Stations – Detection and Alarms (**Performance Test**) ***Notes: There are no compressor stations.***			X	
.709	.739	Pressure Limiting and Regulating Stations (**1 per yr/15 months**) ***Notes: The over –pressure protection is provided by Williams.***			X	
.709	.743	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**) ***Notes: The over – pressure protection is provided by Williams.***			X	
.709	.745	Valve Maintenance (**1 per yr/15 months**)	X			
.709	.749	Vault Maintenance (**≥ 200 cubic feet)(1 per yr/15 months**) ***Notes: There are no vaults for this pipeline.***			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 ***Notes: The operator use contractor for NDT.***			X	
.709	.243(f)	NDT Records (**Pipeline Life**) ***Notes: There were no new construction during this inspection period.***			X	
.709		Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**) ***Notes: There were no repairs during this inspection period.***			X	

Comments:

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.

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 ***Notes: There was no exposed pipe during this inspection period.***			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**) ***Notes: There were no interference bonds.***			X	
.491	.465(c) Interference Bond Monitoring – Non-critical (**1 per yr/15 months**) ***Notes: There were no interference bonds.***			X	
.491	.465(d) Prompt Remedial Actions ***Notes: There were no remedial actions during this inspection period.***			X	
.491	.465(e) Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) ***Notes: There were no unprotected pipelines.***			X	
.491	.467 Electrical Isolation (**Including Casings**)	X			
.491	.469 Test Stations – Sufficient Number	X			
.491	.471 Test Leads	X			
.491	.473 Interference Currents ***Notes: There were no interference currents on Washington side of the pipeline.***			X	
.491	.475(a) Internal Corrosion; Corrosive Gas Investigation	X			
.491	.475(b) Internal Corrosion; Internal Surface Inspection; Pipe Replacement ***Notes: There was no pipe replacement during this inspection period.***			X	
.491	.476 (d) Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems ***Notes: There was no new system design during this inspection period.***			X	
.491	.477 Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**) ***Notes: There were no internal corrosion control coupons installed for this pipeline.***			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 ***Notes: There were no repairs or replacements during this inspection period.***			X	

Comments:

Leave this list with the operator.

Recent PHMSA Advisory Bulletins (Last 2 years)

Number	Date	Subject
ADB-07-01	April 27, 2007	Pipeline Safety: Senior Executive Signature and Certification of Integrity Management Program Performance Reports
ADB-07-02	September 6, 2007	Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-07-02	February 29, 2008	Correction - Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-08-01	May 13, 2008	Pipeline Safety - Notice to Operators of Gas Transmission Pipelines on the Regulatory Status of Direct Sales Pipelines
ADB-08-02	March 4, 2008	Pipeline Safety - Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems
ADB-08-03	March 10, 2008	Pipeline Safety - Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems
ADB-08-04	June 5, 2008	Pipeline Safety - Installation of Excess Flow Valves into Gas Service Lines
ADB-08-05	June 25, 2008	Pipeline Safety - Notice to Hazardous Liquid Pipeline Operators of Request for Voluntary Adv Notification of Intent To Transport Biofuels
ADB-08-06	July 2, 2008	Pipeline Safety - Dynamic Riser Inspection, Maintenance, and Monitoring Records on Offshore Floating Facilities

For more PHMSA Advisory Bulletins, go to http://ops.dot.gov/regs/advise.htm