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:	Al Jones / UTC	**Inspector/Submit Date:**	Al Jones / June 30, 2011
		Peer Review/Date:	
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	Williams Gas Pipeline - West	**OPID #:**	13845
Name of Unit(s):	Sumas District	**Unit #(s):**	8355
Records Location:	Sumas, Washington	**Activity #**	
Unit Type & Commodity:	Natural Gas		
Inspection Type:	Standard	**Inspection Date(s):**	June 13-17, 2011
PHMSA Representative(s):	Al Jones / UTC		

Company System Maps (copies for Region Files): Sumas, Washington

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 Sumas District inspection included record review, standard inspection report, drug & alcohol questions, OQ field inspection, IMP field verification, SCC supplemental questionnaire, and public awareness program. The field inspection include the Sumas and Mt. Vernon compressor stations for gas detection, ventilation, ESD system, fire extinguishers, gas blow down location, signs, atmospheric corrosion, and control/monitor station. Right-of-way inspection included pipe-to-soil potentials, rectifier stations, valve operations, and Skagit River span crossing.

Inspected the completed integrity upgrades including:

A. August 2009 – recoated 70 feet of 30-inch pipe at Mt. Vernon Compressor Station, between the discharge point and the pulsation bottle. The work was undertaken to repair substandard coating and to enhance cathodic polarization.

B. November 2009 – NDT was completed on the 30-inch incoming line supports and straps to the Sumas Compressor Station yard. The pipe was evaluated for possible corrosion cells between the metal plate on the concrete support and the pipeline. There is no dielectric material placed between the pipeline and the supports. Short Range Guided Waves was used to evaluate 0.500" pipe wall at ten locations. The south support was of interest because it included a girth weld south of pipe strap #9 in the guided wave data. See Exhibit "A" of PIM report from Coast Wave ISONIC Investigation report for support and girth weld image. All locations were found acceptable with minimal corrosion. No additional evaluation or remediation is scheduled for this section of pipe.

C. August 2010 – recoated 85 feet of 30-inch header manifold and twelve 12" x 8" vertical meter tubes at the West Coast Meter Station in the Sumas Compressor Station yard. During the project 400 linear feet of distributed anode was placed around the West Coast Meter Station and the south and east side of B-Plant Compressor Station. The project repaired substandard coating and enhanced cathodic potentials at the B-Plant.

D. October 2010 – installed 5,168 feet of anode-flex adjacent to the 30-inch (#1401 mainline) at Jackson Creek between MP 1,454.92 and MP 1,455.90. The project increased the mainline polarization in rocky ground and high resistivity soil.

E. June 2010 – installed a string of canister anodes around valves 17L-4 and 17L2-4 at Bryant Valve Station, MP 1,427.46. The ground bed addition was completed to enhance cathodic polarization of the mainline valves.

Findings:

No probable violations were identified.

Pipe-to-soil potentials readings were in compliance with -850 mv, on. Aboveground piping is in good condition, coated with durable paint or two part epoxy.

Williams provides overpressure protection for the short section of piping between their meter station and the LDC. The overpressure protection valve at the A &M and Lynden Meter Stations are at maximum value of MAOP plus 10%.

STANDARD INSPECTION REPORT OF A GAS TRANSMISSION PIPELINE

Name of Operator:	Williams Gas Pipeline - West		
OP ID No. (1)		**Unit ID No.** (1)	
HQ Address:		**System/Unit Name & Address:** (1)	
2800 Post Oak Blvd. MC 1060/12314 Houston, TX 77056		4738 Jones Road Sumas, Washington 98295	
Co. Official:	Randy Barnard	**Activity Record ID No.:**	
Phone No.:	(713) 215-2375	**Phone No.:**	(360) 988-2261
Fax No.:	(713) 215-4269	**Fax No.:**	(360) 988-9105
Emergency Phone No.:	(800) 972-7733	**Emergency Phone No.:**	(800) 972-7733

Persons Interviewed	**Title**	**Phone No.**
Justin Adams	Sumas District Manager	(360) 988-2261
Randy Tarter	Assistant District Manager	(360) 988-0500
Dustin Wallis	Pipeline Safety	(801) 584-6599
Kevin Henson	Team Lead Sumas District	(360) 988-2261
Justin Reynolds	Integrity Lead – North	(509) 290-1918
Jeff Pollack	Senior Integrity	(206) 890-6259
Brian Hall	Control Specialist	(360) 988-2261
Chris Wolf	Control Specialist	(360) 988-2261
Sam Chestnut	Operation Technician III	(360) 988-2261
Kim Nelson	Operation Technician IV	(360) 988-2261
Mike Fitchner	Operation Technician V	(360) 988-2261

PHMSA Representative(s) (1)	Al Jones / UTC	**Inspection Date(s)** (1)	June 13-17, 2011
Company System Maps (Copies for Region Files):	Sumas, Washington		

Unit Description:

The Sumas District receives natural gas from West Coast Energy at the Canadian border. The gas pressure is increased at the Sumas compressor station then transported south by two parallel 30" and 36" pipelines. The Sumas District extends south to State Route 92 south of Marysville at MP 1411 including approximately, 73.3 and 60.4 ROW miles of 30-inch and 36-inch transmission mainline, respectively. Most of the lines are in class 1 or 2 locations except for class 3 locations at Arlington, Deming and Stanwood. There are two compressor stations, on at Sumas and the other at Mt. Vernon. The MAOP of the pipeline system is 960 psig.

In addition to the mainlines, the following laterals are within the District:

Stanwood Lateral – 8.3 mile of 6" line
Bellingham Lateral – 11.5 miles of 6" and 12" lines.

Portion of Unit Inspected: (1)

See summary paragraph, above.

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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 03/16/06 and 03/17/2011.

	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. Operator must have a written procedure for calculating an initial estimate of the amount of product released in an accident. (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			X	
.605(d)	Instructions to enable operation and maintenance personnel to recognize potential **Safety Related Conditions**	X			

Comments:
Operator has no offshore pipeline ins District.
O&M Procedure 10.08

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			
	.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 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).			X	

Comments:
O&M Procedure 10.14
Control room management O&M Procedure must be developed by August 1, 20ll and take effect on February 1, 2013.

.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:
O&M Procedure 10.02

.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:
O&M Procedure 10.9

.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:

O&M Procedure 70.06

.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:

Williams uses a qualified one call center.
O&M Procedure 10.17

.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(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	X			

Comments:
O&M Procedure 10.21

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.					
	.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:
O&M Procedure 10.17

.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:
O&M Procedure 10.18

.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.

	(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:
O&M Procedure 70.08

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

Comments:
O&M Procedure 70.04

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

Comments:
O&M Procedure 70.05

.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:
O&M Procedure 60.01

.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:
O&M Procedure for tapping pipelines is 90.11
O&M Procedure for purging pipelines is 10.22

*			**CONTROL ROOM MANAGEMENT PROCEDURES** (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	**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	

*		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 192-112, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
		(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.				
	.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	
		(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:
O&M Procedure must be developed by August 1, 20ll and take effect on February 1, 2013.

.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:
O&M Procedure 70.14

.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			
		(b) **Class 4** locations - **4½ months** but at least **4 times 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)**

Comments:
O&M Procedure 70.10

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

Comments:
O&M Procedure 70.12

.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:
O&M Procedure Form 092

.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			
		(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:
O&M Procedure 70.14 & 90.12

.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:
O&M Procedure 70.15

.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:
O&M Procedure 15.03, 60.02, & 30.03

<table>
<tr><th>.605(b)</th><th></th><th>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>X</td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td>(1) In good mechanical condition</td><td>X</td><td></td><td></td><td></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>X</td><td></td><td></td><td></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).</td><td>X</td><td></td><td></td><td></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>X</td><td></td><td></td><td></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 . . .</td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td><table>
<tr><th>If MAOP produces hoop stress that</th><th>Then the pressure limit is:</th></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>X</td><td></td><td></td><td></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.</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td></td><td>.743</td><td>(b) If calculated, capacities must be compared; annual review and documentation are required.</td><td>X</td><td></td><td></td><td></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>X</td><td></td><td></td><td></td></tr>
</table>

Comments:
O&M Procedure 60.02

.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			

.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**).				

Comments:
O&M Procedure 70.16
Williams does not have vaults greater than 200 CF.

.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:
O&M Procedure 65.00

.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.	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).	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.	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 **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	X			

.13(c)			**WELDING AND WELD DEFECT REPAIR/REMOVAL PROCEDURES**	S	U	N/A	N/C
			(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:
O&M Procedure 90.03, 90.09, 90.10, & 90,54
Williams does not use Section 1 of Appendix C or on pipe <20% SMYS to qualify welders.
Williams qualifies welders more frequently than annually.

.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:
O&M Procedure 90.09

.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. 192-103 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:
Williams does not use plastic gas pipe.

.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			

.605(b)		**CORROSION CONTROL PROCEDURES**	S	U	N/A	N/C
		(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.	X			
		(b) Exceptions – offshore pipeline and systems replaced before 5/23/07. Final Rule Pub. 4/23/07, eff. 5/23/07.	X			
*		(c) Evaluate impact of configuration changes to existing systems. Final Rule Pub. 4/23/07, eff. 5/23/07.	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			
	.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:

O&M Procedure 20.02 - 20.16

Williams does not use aluminum pipeline.

.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 ___	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	

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.

.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:
Williams does not have underwater crossing in the Sumas District.

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			
.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	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)	X			
.745	Valve Maintenance	X			
.751(c)	Warning Signs Posted	X			

Comments:
Williams does not have pipelines expose on seabeds.

COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) ____		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			

COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c) ____		**S**	**U**	**N/A**	**N/C**
.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…				
	- 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:

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:

Gas sensors in compressor building will alarm at 20% LEL and ESD the station at 40% LEL.

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)~~			X	
191.12	Mechanical Fitting Failure Report (DOT Form PHMSA 7100.1-2) - if a fitting failure happened in the previous year.			X	
191.15	Written incident reports; supplemental incident reports (DOT Form PHMSA F 7100.2)	X			
191.17 (a)	Annual Report (DOT Form PHMSA F 7100.2-1)	X			
191.23	Safety related condition reports			X	
191.27	Offshore pipeline condition reports			X	
192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports			X	

CONSTRUCTION PERFORMANCE and RECORDS		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			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			

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.

		OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS	**S**	**U**	**N/A**	**N/C**
.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.	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)	
	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.	

X

			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			

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.

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.

		OPERATIONS and MAINTENANCE PERFORMANCE and RECORDS	S	U	N/A	N/C
.709	.731(a)	Compressor Station Relief Devices (**1 per yr/15 months**)	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			
.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:
The Sumas District did not convert to service any pipeline, had no mechanical fitting failures, safety related condition reports, abnormal conditions, vaults greater than 200 CF, or abandoned facilities.
There has been no construction activity of new piping since the last inspection, thus no welding records to review.

		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**)			X	
.491	.465(c)	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**)	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**)			X	
.491	.467	Electrical Isolation (**Including Casings**)	X			
.491	.469	Test Stations – Sufficient Number	X			
.491	.471	Test Leads	X			
.491	.473	Interference Currents	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	X			

		CORROSION CONTROL PERFORMANCE and RECORDS	S	U	N/A	N/C
.491	.477	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**)			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:
The Sumas District does not have unprotected pipelines, critical interference bonds, and coupons. Internal corrosion is monitored by gas and liquid analysis.

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

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				
.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			X	
	(i) Assess adequacy of CIS and perform DCVG or ACVG within 6 months				
	(ii) Remediate damage with IR drop > 35%			X	
	(iii) Integrate internal inspection results with indirect assessment			X	
	(iv) Periodic assessments for HCAs			X	
	(A-C) Close interval surveys, test stations at ½ mile intervals, and integrate results				
	(8) Cathodic Protection			X	
	(i) Complete remediations within 6 months of failed reading				
	(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			X	
	(i)(A) Geometry tool run within 6 months of service				
	(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			X	
	(i) Frequency for assessments determined as if all segments covered by Subpart O				
	(ii) Inspect using MFL tool or direct assessment per §192.925, 927, 929 or pressure testing.			X	
	(11) Repairs			X	
	(i)(A) Use of the most conservative calculation for anomaly remaining strength				
	(B) Tool tolerances taken into consideration			X	
	(ii) Immediate repairs for:			X	
	(A) Dents meeting 309(b) criteria				
	(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:			X	
	(A) Defects meeting 1 year criteria in 933(d)				
	(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:
The Sumas District does not use the Alternative MAOP criteria.

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	Williams Gas Pipeline West – Northwest Pipeline	**Op ID #**	13845
Inspector	Al Jones / UTC	**Unit #**	8355
Date of Inspection	June 13 -17, 2011		
Inspection Location City & State	Sumas, Washington		
Operator Employee Interviewed	Dustin Wallis	**Phone #**	801-584-6599
Position/Title	Pipeline Safety		
Operator Designated Employer Representative (DER), (a.k.a. Substance Abuse Program Manager)	Merle A. Bowler		
DER Phone #	713-215-2422		

§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	A. Yes, see WGP Drug Plan-General Provisions Section II. Applicability (page 6). B. Yes, contractors are screened through 3rd Part Administrator National Compliance Management Services (NCMS) or other third part vendors.			
.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	A. Yes, see WGP Drug Plan – Reasonable Cause Test (page 6) Testing is done multiple times per year with a variety of test performed each time with 25% of the test pool is tested annually as per DOT PHMSA Drug and Alcohol Testing Regulations. B. Yes, See WGP Alcohol Plan – Reasonable Suspicion 1. Decision to Test (page 7).			
.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	A. Yes, see WGP Drug Plan – Section III. TEST REQUIRED B. Post-Accident Test (page 5) Time Limit 32 hours. Field Managers are responsible for making the decision to test. B. Yes, see WGP Alcohol Plan – Section III. TEST REQUIRED A. Post-Accident Test (page 6) Time Limit 2 – 8 hours. Field Managers are responsible for making the decision to test. C. General Provisions Section 1. OVERVIEW C. Responsibilities 3. Management is responsible for ensuring post-accident testing occurs.			
.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	A. Yes, see WGP General Provisions – Section V. EMPLOYEE ASSISTANCE PROGRAM B. Training.			
.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	Yes, see WGP General Provisions – Section V. EMPLOYEE ASSISTANCE PROGRAM.			