Utilities and Transportation Commission
Standard Inspection Report for Intrastate Gas Transmission Pipelines
Form D - Records Review and Field Inspection

A completed **Standard Inspection Checklist, Cover Letter and Field Report** is to be submitted to the Senior Engineer within 30 days from completion of the inspection.

Inspection Report			
Insp ID / Docket Number	2589		
Inspector Name & Submit Date	Lex Vinsel, 9/13/2012		
Chief Eng Name & Review Date	Joe Subsits, 9/14/2012		
Operator Information			
Name of Operator:	Lamb Weston/BSW	**OP ID #:**	32560
Name of Unit(s):	Warden, WA		
Records Location:	Warden, WA		
Date(s) of Last (unit) Inspection:	May 2010	**Inspection Date(s):**	August 6-10, 2012

Inspection Summary:

The Lamb Weston/BSW intrastate transmission line runs from the Williams gate station (and R46) to the R26 regulator station on NE corner of Road U and County Line Road. A HP line then exits R26 and comes up inside the processing plant in Warden WA.

Williams provides natural gas (gas) at 700-800 PSIG to the inlet MAOP 809 of Regulator R46. Regulator R46 outlet MAOP is 150 PSIG. The pipeline is X46 6-inch diameter with 0.188 inch wall. From R46 the pipeline crosses under Road 6 (North) and turns West to parallel Road 6 on the North side. The 6-inch pipeline continues West till just east of the intersection with County Line Road. The pipeline goes under Road 6 again and travels South on the East side of County Line Road. When the pipeline cones even with the R26 regulator just past Basin Street the pipeline turns under County Line Rd and enters the regulator station on the NE corner of the intersection. 6-inch MAOP of 150 PSIG on the inlet side of R26 and outlet is 4-inch with MAOP of 150 PSIG that operates at 100 PSIG to the plant.

Item 96 - Review operator locating and excavation procedures for compliance with state law and regulations. **Lamb Weston / BSE Operations & Maintenance Manual, Section #7.03 refers to Oregon instead of Washington one call This was fixed.**

HQ Address:	**System/Unit Name & Address:**
1203 Basin Street Warden, WA 98857	
Co. Official: Marvin Price **Phone No.:** 509-349-2210 ext 54704 **Fax No.:** **Emergency Phone No.:** 509-750-6193	**Phone No.:** **Fax No.:** **Emergency Phone No.:**

Persons Interviewed	Title	Phone No.
Marvin Price	Manager, Energy & Environment	509-349-2210 ext 54704
Kevin O'Hogan	Operator, NW Metal Fab	503-793-7045
Andy Bateman	Plant Manager	509-349-2210 ext. 54200

UTC staff conducted abbreviated procedures inspection on 192 O&M and WAC items that changed since the last inspection. This checklist focuses on Records and Field items per a routine standard inspection.

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(check one below and enter appropriate date)			
☐	Team inspection was performed (Within the past five years.) or,	**Date:**	
☒	Other UTC Inspector reviewed the O & M Manual (Since the last yearly review of the manual by the operator.) **O&M Manual currently being reviewed**	**Date:**	2011

GAS SYSTEM OPERATIONS			
Gas Supplier	Williams		
Number of reportable safety related conditions last year 0		Number of deferred leaks in system 0	
Number of non-reportable safety related conditions last year 0		Number of third party hits last year 0	
Miles of transmission pipeline within unit (total miles and miles in class 3 & 4 areas) 4.0 miles in Class 2			
Operating Pressure(s):		**MAOP (Within last year)**	**Actual Operating Pressure** **(At time of Inspection)**
Feeder:	Williams	809	150 for 6-inch, 100 for 4-inch
Town:			
Other:			
Does the operator have any transmission pipelines?	4.0 Miles of Class 2		
Compressor stations? Use Attachment 4.	No compressor stations		

Pipe Specifications:			
Year Installed (Range)	2000	Pipe Diameters (Range)	6-inch & 4-inch
Material Type	X46, 0.188 wall	Line Pipe Specification Used	API 5L
Mileage	4.0 miles to first cut to 100 PSIG	SMYS %	Below 20% is 10.4% @ 150 PSIG
Supply Company	Williams	Class Locations	Class 2

Integrity Management Field Validation

Important: Per PHMSA, IMP Field Verification Form 16 (Rev 3/19/2010) shall be used by the inspector as part of this standard inspection. When completed, the inspector will upload this information into the PHMSA IM Database (IMDB) located at http://primis.phmsa.dot.gov/gasimp/home.gim **Date Completed: Lamb Weston performed a class location study and found no class three or four sections on their pipeline.**

PART 199 DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES		**S**	**U**	**NA**	**NC**
Subparts A - C	Drug & Alcohol Testing & Misuse Prevention Program – Use PHMSA Form #13, Rev 3/19/2010. Do not ask the company to have a drug and alcohol expert available for this portion of your inspection. Form 13 sent to stanley.kastanas@dot.gov	X			

PART 192 Implement Applicable Control Room Management Procedures		**S**	**U**	**NA**	**NC**
.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). **No control room in system.**			X	

REPORTING RECORDS			**S**	**U**	**N/A**	**N/C**
1.	49 U.S.C. 60132, Subsection (b)	**Submission of Data to the National Pipeline Mapping System Under the Pipeline Safety Improvement Act of 2002**	X			

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		REPORTING RECORDS	S	U	N/A	N/C
	ADB-08-07	Updates to NMPS: Operators are required to make update submissions every 12 months if any system modifications have occurred. Go to http://www.npms.phmsa.dot.gov/submission/ to review existing data on record. Also report no modifications if none have occurred since the last complete submission. Include operator contact information with all updates.				
2.	RCW 81.88.080	Pipeline Mapping System: Has the operator provided accurate maps (or updates) of pipelines, operating over two hundred fifty pounds per square inch gauge, to specifications developed by the commission sufficient to meet the needs of first responders? **Pipeline operates at less than 250 PSIG.**			X	
3.	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). **NW was unable to locate the written procedure for calculating an initial estimate of the amount of product released in an accident. To be addressed in the O&M review.**		X		
4.	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). **None**			X	
5.	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). **None**			X	
6.	191.15(c)	Supplemental report (to 30-day follow-up) **None**			X	
7.	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			
8.	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			
9.	191.23	Safety related condition reports **None**			X	
10.	191.25	Filing the SRCR within 5 days of determination, but not later than 10 days after discovery **None**			X	
11.	192.727(g)	Abandoned facilities offshore, onshore crossing commercially navigable waterways reports **None**			X	
12.	480-93-200(1)	Telephonic Reports to UTC **Pipeline Safety Incident Notification 1-888-321-9146** (Within **2 hours**) for events which **(regardless of cause)**; **None**				
13.	480-93-200(1)(a)	Result in a fatality or personal injury requiring hospitalization; **None**			X	
14.	480-93-200(1)(b)	Results in damage to property of the operator and others of a combined total exceeding fifty thousand dollars; **None** **Note:** Report all damages regardless if claim was filed with pipeline company or not.			X	
15.	480-93-200(1)(c)	Results in the evacuation of a building, or high occupancy structures or areas; **None**			X	
16.	480-93-200(1)(d)	Results in the unintentional ignition of gas; **None**			X	
17.	480-93-200(1)(e)	Results in the unscheduled interruption of service furnished by any operator to twenty five or more distribution customers; **None**			X	
18.	480-93-200(1)(f)	Results in a pipeline or system pressure exceeding the MAOP plus ten percent or the maximum pressure allowed by proximity considerations outlined in WAC 480-93-020;			X	
19.	480-93-200(1)(g)	Is significant, in the judgment of the operator, even though it does not meet the criteria of (a) through (e) of this subsection; or			X	
20.	480-93-200(2)	Telephonic Reports to UTC **Pipeline Safety Incident Notification 1-888-321-9146** (Within **24 hours**) for;			X	
21.	480-93-200(2)(a)	The uncontrolled release of gas for more than two hours; **None**			X	
22.	480-93-200(2)(b)	The taking of a high pressure supply or transmission pipeline or a major distribution supply pipeline out of service; **None**			X	

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		REPORTING RECORDS	S	U	N/A	N/C
23.	480-93-200(2)(c)	A pipeline operating at low pressure dropping below the safe operating conditions of attached appliances and gas equipment; or **None**			X	
24.	480-93-200(2)(d)	A pipeline pressure exceeding the MAOP **None**			X	

Comments:

25.	480-93-200(5)	Written incident reports (within 30 days) including the following;	S	U	N/A	N/C
26.	480-93-200(4)(a)	Name(s) and address(es) of any person or persons injured or killed, or whose property was damaged; **No incidents**			X	
27.	480-93-200(4)(b)	The extent of injuries and damage; **No incidents**			X	
28.	480-93-200(4)(c)	A description of the incident or hazardous condition including the date, time, and place, and reason why the incident occurred. If more than one reportable condition arises from a single incident, each must be included in the report; **No incidents**			X	
29.	480-93-200(4)(d)	A description of the gas pipeline involved in the incident or hazardous condition, the system operating pressure at that time, and the MAOP of the facilities involved; **No incidents**			X	
30.	480-93-200(4)(e)	The date and time the gas pipeline company was first notified of the incident; **No incidents**			X	
31.	480-93-200(4)(f)	The date and time the ((operators')) gas pipeline company's first responders arrived on-site; **No incidents**			X	
32.	480-93-200(4)(g)	The date and time the gas ((facility)) pipeline was made safe; **No incidents**			X	
33.	480-93-200(4)(h)	The date, time, and type of any temporary or permanent repair that was made; **No incidents**			X	
34.	480-93-200(4)(i)	The cost of the incident to the ((operator)) gas pipeline company; **No incidents**			X	
35.	480-93-200(4)(j)	Line type; **No incidents**			X	
36.	480-93-200(4)(k)	City and county of incident; and **No incidents**			X	
37.	480-93-200(4)(l)	Any other information deemed necessary by the commission. **No incidents**			X	
38.	480-93-200(5)	Submit a supplemental report if required information becomes available **No incidents**			X	
39.	480-93-200(6)	Written report within 45 days of receiving the failure analysis of any **incident or hazardous condition** due to **construction defects or material failure No incidents**			X	

Comments:

40.	480-93-200(7)	**Annual Reports** filed with the commission no later than **March 15** for the proceeding calendar year	S	U	N/A	N/C
41.	480-93-200(7)(a)	A copy of PHMSA F-7100.1-1 and F-7100.2-1 annual report required by U.S. Department of Transportation, PHMSA/Office of Pipeline Safety **Annual reports received by Marina on Thursday, March 08, 2012.**	X			
42.	480-93-200(7)(b)	Damage Prevention Statistics Report including the following; **Annual reports received by Marina on Thursday, March 08, 2012.**	X			

			S	U	N/A	N/C
43.	480-93-200(7)(b)(i)	Number of gas-related one-call locate requests completed in the field;	X			
44.	480-93-200(7)(b)(ii)	Number of third-party damages incurred; and **None**			X	
45.	480-93-200(7)(b)(iii)	Cause of damage, where cause of damage is classified as **No incidents** one of the following: (A) Inaccurate locate; (B) Failure to use reasonable care; (C) Excavated prior to a locate being conducted; or (D) Other			X	
46.	480-93-200(7)(c)	Reports detailing all construction defects and material failures resulting in leakage. Categorizing the different types of construction defects and material failures. The report must include the following: (i) Types and numbers of construction defects; and (ii) Types and numbers of material failures. **None**			X	
47.	480-93-200(8)	Providing updated emergency contact information to the commission and appropriate officials of all municipalities where gas pipeline companies have facilities	X			
48.	480-93-200(9)	Providing by email, reports of daily construction and repair activities no later than 10:00 a.m. **No construction activity on pipeline.**			X	
49.	480-93-200(10)	Submitting copy of DOT Drug and Alcohol Testing MIS Data Collection Form when required	X			

Comments:

		CONSTRUCTION RECORDS	**S**	**U**	**N/A**	**N/C**
50.	192.225	Test Results to Qualify Welding Procedures **No construction during time period**			X	
51.	192.227	Welder Qualification **No construction during time period**			X	
52.	192.241(a)	Visual Weld Inspector Training/Experience **No construction during time period**			X	
53.	192.243(b)(2)	Nondestructive Technician Qualification **No construction during time period**			X	
54.	192.243(c)	NDT procedures **No construction during time period**			X	
55.	192.243(f)	Total Number of Girth Welds **No construction during time period**			X	
56.	192.243(f)	Number of Welds Inspected by NDT **No construction during time period**			X	
57.	192.243(f)	Number of Welds Rejected **No construction during time period**			X	
58.	192.243(f)	Disposition of each Weld Rejected **No construction during time period**			X	
59.	480-93-080(1)(b)	Use of testing equipment to record and document essential variables **No construction during time period**			X	
60.	480-93-115(2)	Test leads on casings (without vents) installed after 9/05/1992 **No construction during time period**			X	
61.	480-93-115(3)	Sealing ends of casings or conduits on Transmission lines and main **No construction during time period**			X	
62.	480-93-115(4)	Sealing ends (nearest building wall) of casings or conduits on services **No construction during time period**			X	
63.	192.303	Construction Specifications **No construction during time period**			X	
64.	192.325	Underground Clearance **No construction during time period**			X	
65.	192.327	Amount, Location, Cover of each Size of Pipe Installed **No construction during time period**			X	

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CONSTRUCTION RECORDS			S	U	N/A	N/C
66.	192.328	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? **No construction during time period**			X	
67.	480-93-160(1)	Detailed report filed 45 days prior to construction or replacement of transmission pipelines ≥ 100 feet in length **No construction during time period**			X	
68.	480-93-170(3)	Pressure Tests Performed on new and replacement pipelines **No construction during time period**			X	
69.	480-93-170(10)	Pressure Testing Equipment checked for Accuracy/Intervals (Manufacturers Recom or Operators schedule) **No construction during time period**			X	
70.	480-93-175(1)	Study prepared and approved prior to moving and lowering of metallic pipelines > 60 psig **No construction during time period**			X	
71.	192.455	Cathodic Protection **No construction during time period**			X	

Comments:

OPERATIONS and MAINTENANCE RECORDS			S	U	N/A	N/C
72.	192.14	**Conversion To Service Performance and Records**				
73.	192.14 (a)(2)	Visual inspection of right of way, aboveground and selected underground segments **No conversion to service.**			X	
74.	192.14 (a)(3)	Correction of unsafe defects and conditions **No conversion to service.**			X	
75.	192.14 (a)(4)	Pipeline testing in accordance with Subpart J **No conversion to service.**			X	
76.	192.14 (b)	Pipeline records: investigations, tests, repairs, replacements, alterations (life of pipeline) **No conversion to service.**			X	
77.	192.16	Customer Notification (**Verification – 90 days – and Elements**) **No services**			X	
78.	192.603(b)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**) .605(a) **Note:** Including review of OQ procedures as suggested by PHMSA - ADB-09-03 dated 2/7/09 **Performed by Marvin**	X			
79.	192.603(b)	Abnormal Operations .605(c) **None**	X			
80.	192.603(b)	Availability of construction records, maps, operating history to operating personnel .605(b)(3) **Maps and records adequate.**	X			
81.	192.603(b)	Periodic review of personnel work – effectiveness of normal O&M procedures .605(b)(8) **Marvin reviews the O&M procedures annually for 2011 & 2012**	X			
82.	192.603(b)	Periodic review of personnel work – effectiveness of abnormal operation procedures .605(c)(4) **None**	X			
83.		**Damage Prevention Program**				
84.	192.603(b)	List of Current Excavators .614 (c)(1) **Only one excavator Central in this area**	X			
85.	192.603(b)	Notification of Public/Excavators .614 (c)(2)	X			
86.	192.603(b)	Notifications of planned excavations. (One -Call Records) .614 (c)(3) **Yes**	X			
87.	.614(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:				
88.		1. Is the inspection done as frequently as necessary during and after the activities to verify the integrity of the pipeline? **None**	X			

		OPERATIONS and MAINTENANCE RECORDS	S	U	N/A	N/C
89.		2. In the case of blasting, does the inspection include leakage surveys? (required) **None**	X			
90.	**Damage Prevention (Operator Internal Performance Measures)**					
91.	Does the pipeline operator voluntarily submit pipeline damage statistics into the UTC Damage Information Reporting Tool (DIRT)? Operator may register at https://identity.damagereporting.org/cgareg/control/login.do Y N x **Operator has nothing to report.**					
92.		Does the operator have a quality assurance program in place for monitoring the locating and marking of facilities? Do operators conduct regular field audits of the performance of locators/contractors and take action when necessary? (CGA Best Practices v. 6.0, Best Practice 4-18. Recommended only, not required) **Operator and Operations Contractor are the same people that do the locating.**	X			
93.		Does operator including performance measures in facility locating services contracts with corresponding and meaningful incentives and penalties? **Operator and Operations Contractor are the same people that do the locating.**	X			
94.		Do locate contractors address performance problems for persons performing locating services through mechanisms such as re-training, process change, or changes in staffing levels? **Operator and Operations Contractor are the same people that do the locating.**	X			
95.		Does the operator periodically review the Operator Qualification plan criteria and methods used to qualify personnel to perform locates? **Operator and Operations Contractor are the same people that do the locating.**	X			
96.		Review operator locating and excavation procedures for compliance with state law and regulations. **Lamb Weston / BSE Operations & Maintenance Manual, Section #7.03 refers to Oregon instead of Washington one call.**	X			
97.		Are locates are being made within the timeframes required by state law and regulations? Examine record sample.	X			
98.	195.507(b)	Are locating and excavating personnel properly qualified in accordance with the operator's Operator Qualification plan and with federal and state requirements? **Yes**	X			
99.	192.709	Class Location Study (**If Applicable**) .609 **NO STUDY REQUIRED, pipeline operates at less than 40% SMYS**			X	
100.	192.605(a)	Confirmation or revision of MAOP. Final Rule Pub. 10/17/08, eff. 12/22/08. .611 **MAOP is below pressure requiring revision.**			X	
101.	192.603(b)	Prompt and effective response to each type of emergency .615(a)(3) **Note:** Review operator records of previous accidents and failures including third-party damage and leak response **No accidents or failures.**	X			
102.	192.615	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). .615(a)(11) **No controller or control room for segment.**			X	
103.	192.603(b)	Location Specific Emergency Plan .615(b)(1) **Section 8**	X			
104.	192.603(b)	Emergency Procedure training, verify effectiveness of training .615(b)(2) **Training Provided**	X			
105.	192.603(b)	Employee Emergency activity review, determine if procedures were followed. .615(b)(3) **No incidents to measure effectiveness.**	X			
106.	192.603(b)	Liaison Program with Public Officials .615(c) **Section 8**	X			

Comments:

		Public Awareness Program .616	S	U	N/A	N/C
192.603(b)		Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. See 192.616(a) and (j) for exceptions.				
		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

* Refer to API RP 1162 for additional requirements, including general program recommendations, supplemental requirements, recordkeeping, program evaluation, etc.

			S	U	N/A	N/C
107.	192.603(b)	The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: .616(d) (1) Use of a one-call notification system prior to excavation and other damage prevention activities; (2) Possible hazards associated with the unintended release from a gas pipeline facility (3) Physical indications of a possible release; (4) Steps to be taken for public safety on the event of a gas pipeline release; and (5) Procedures to report such an event (to the operator).	X			
108. **109.**	192.603(b)	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.). .616 (e) & (f)	X			
110.	192.603(b)	The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area. .616(g)	X			
111.	192.603(b)	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**. .616(h) **Operator not in existence on June 20, 2005, previous operator was CNG.**	X			
112.	192.603(b)	Analyzing accidents and failures including laboratory analysis where appropriate to determine cause and prevention of recurrence .617 **Note:** Including excavation damage (PHMSA area of emphasis)**No incidents**			X	

Comments:

Public Awareness Program is Section #10 of O&M Manual

<table>
<tr><td>113.</td><td>192.517</td><td>Pressure Testing None during time period.</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>114.</td><td>.553(b)</td><td>Uprating No uprating planned or expected.</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>115.</td><td>192.709</td><td>Maximum Allowable Operating Pressure (MAOP)</td><td></td><td></td><td></td><td></td></tr>
<tr><td>116.</td><td rowspan="3">.709</td><td>Note: If the operator is operating at 80% SMYS with waivers, the inspector needs to review the special conditions of the waiver.</td><td></td><td></td><td></td><td></td></tr>
<tr><td>117.</td><td>MAOP cannot exceed the lowest of the following: .619 Section 12</td><td></td><td></td><td></td><td></td></tr>
<tr><td>118.</td><td>Design pressure of the weakest element, .619(a)(1) Amdt, 192-103 pub. 06/09/06, eff. 07/10/06 Not applicable</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>119.</td><td rowspan="3">.709</td><td>The highest actual operating pressure to which the segment of line was subjected during the 5 years preceding the applicable date in the second column, unless the segment was tested in 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. .619(a)(3)
<table>
<tr><th>Pipeline segment</th><th>Pressure date</th><th>Test date</th></tr>
<tr><td>-Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006.</td><td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td><td>5 years preceding applicable date in second column.</td></tr>
<tr><td>Offshore gathering lines</td><td>July 1, 1976</td><td>July 1, 1971</td></tr>
<tr><td>All other pipelines</td><td>July 1, 1970</td><td>July 1, 1965</td></tr>
</table></td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>120.</td><td>.619(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.</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>121.</td><td>.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
Mill hydrostatic testing
Coating
Fittings and flanges
Compressor stations Final rule pub. 10/17/08, eff. 12/22/08</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>122.</td><td>480-93-015(1)</td><td>Odorization of Gas – Concentrations adequate Section 13 Reviewed 2011 and 1st half of 2012, reviewed 2009 by CNG records.</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>123.</td><td>480-93-015(2)</td><td>Monthly Odorant Sniff Testing Section 13 Reviewed 2011 and 1st half of 2012, reviewed 2009 by CNG records.</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>124.</td><td>480-93-015(3)</td><td>Prompt action taken to investigate and remediate odorant concentrations not meeting the minimum requirements None</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>125.</td><td>480-93-015(4)</td><td>Odorant Testing Equipment Calibration/Intervals (Annually or Manufacturers Recommendation) Annual</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>126.</td><td>480-93-124(3)</td><td>Pipeline markers attached to bridges or other spans inspected? 1/yr(15 months) Annual</td><td>X</td><td></td><td></td><td></td></tr>
<tr><td>127.</td><td>480-93-124(4)</td><td>Markers reported missing or damaged replaced within 45 days?</td><td>X</td><td></td><td></td><td></td></tr>
</table>

Comments:

128.	480-93-185(1)	Reported gas leaks investigated promptly/graded/record retained **None**			X	
129.	480-93-185(3)	Leaks originating from a foreign source reported promptly/notification by mail/record retained **None**	X			
130.	480-93-187	Gas Leak records **None**			X	
131.	480-93-188(1)	Gas Leak surveys **Annual requirement done twice per year.**	X			
132.	480-93-188(2)	Gas detection instruments tested for accuracy/intervals (Mfct rec or monthly not to exceed 45 days) **Annual**	X			
133.	480-93-188(3)	Leak survey frequency **(Refer to Table Below) Annual survey**	X			

Business Districts (By 6/02/07)	**1/yr (15 months)**
High Occupancy Structures	**1/yr (15 months)**
Pipelines Operating ≥ 250 psig	**1/yr (15 months)**
Other Mains: CI, WI, copper, unprotected steel	**2/yr (7.5 months)**

134.	480-93-188(4)(a)	Special leak surveys - Prior to paving or resurfacing, following street alterations or repairs **None**			X	
135.	480-93-188(4)(b)	Special leak surveys - areas where substructure construction occurs adjacent to underground gas facilities, and damage could have occurred **None**			X	
136.	480-93-188(4)(c)	Special leak surveys - Unstable soil areas where active gas lines could be affected **None**			X	
137.	480-93-188(4)(d)	Special leak surveys - areas and at times of unusual activity, such as earthquake, floods, and explosions **None**			X	
138.	480-93-188(5)	Gas Survey Records **Reviewed 2011 and 1st half of 2012, reviewed 2009 by CNG records.**	X			
139.	480-93-188(6)	Leak Survey Program/Self Audits	X			
140.	192.709	Patrolling (**Refer to Table Below**) .705 **Reviewed 2011 and 1st half of 2012, reviewed 2009 by CNG records.**	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)**

141.	192.709	Leak Surveys (**Refer to Table Below**) .706 **Reviewed 2011 and 1st half of 2012, reviewed 2009 by CNG records.**	X			

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

142.	192.605(b)	Abandoned Pipelines; Underwater Facility Reports .727(g) **None**			X	
143.	192.709	Compressor Station Relief Devices (**1 per yr/15 months**) .731(a) **No compressor**			X	

144.	192.709	Compressor Station Emergency Shutdown (**1 per yr/15 months**) .731(c) **No compressor**			X	
145.	192.709	Compressor Stations – Detection and Alarms (**Performance Test**) .736(c) **No compressor**			X	
146.	192.709	Pressure Limiting and Regulating Stations (**1 per yr/15 months**) .739 **Performed every quarter for 2011 and 1st half of 2012, 2010 from CNG records.**	X			
147.	192.709	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**) .743	X			

Comments:

148.	192.709	Valve Maintenance (**1 per yr/15 months**) .745 **Performed every quarter for 2011 and 1st half of 2012, 2010 from CNG records.**	X			
149.	192.709	Vault Maintenance (≥**200 cubic feet**)(**1 per yr/15 months**) .749 **No vaults**			X	
150.	192.603(b)	Prevention of Accidental Ignition (hot work permits) .751 **None during time period**			X	
151.	192.603(b)	Welding – Procedure .225(b) **None during time period**			X	
152.	192.603(b)	Welding – Welder Qualification .227/.229 **None during time period**			X	
153.	192.603(b)	NDT – NDT Personnel Qualification .243(b)(2) **None during time period**			X	
154.	192.709	NDT Records (**Pipeline Life**) .243(f) **None during time period**			X	
155.	192.709	Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**) **None during time period**			X	
156.	.807(b)	Refer to PHMSA Form # 15 to document review of operator's employee covered task records	X			
157.	192.905(c)	Periodically examining their transmission line routes for the appearance of newly identified area's (HCA's) **None during time period**	X			

Comments:

CORROSION CONTROL RECORDS			S	U	N/A	N/C
158.	192.453	CP procedures (system design, installation, operation, and maintenance) must be carried out by qualified personnel **NACE ID# 9820 Kevin O'Hogan**	X			
159.	192.455(a)(2)	CP system installed on and operating within 1 yr of completion of pipeline construction *(after 7/31/71)*	X			
160.	192.491	Annual Pipe-to-soil Monitoring (**1 per yr/15 months**) for short sections (**10% per year; all in 10 years**) .465(a) **No short sections**			X	
161.	192.491	Maps or Records .491(a) **Available**	X			
162.	192.491	Examination of Buried Pipe when Exposed .459 **None**			X	
163.	480-93-110(8)	CP test reading on all exposed facilities where coating has been removed **None**			X	
164.	192.491	Rectifier Monitoring (**6 per yr/2½ months**) .465(b) **Performed every quarter for 2011 and 1st half of 2012, 2010 from CNG records.**			X	
165.	192.491	Interference Bond Monitoring – Critical (**6 per yr/2½ months**) .465(c) **None**			X	
166.	192.491	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**) .465(c) **None**			X	

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CORROSION CONTROL RECORDS			S	U	N/A	N/C
167.	192.491	Prompt Remedial Actions .465(d) **None**			X	
168.	192.491	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**) .465(e) **No unprotected pipeline.**			X	
169.	192.491	Electrical Isolation (**Including Casings**) .467	X			
170.	480-93-110(2)	Remedial action taken within 90 days (Up to 30 additional days if other circumstances. Must document) .465(d) **None**			X	
171.	480-93-110(3)	CP Test Equipment and Instruments checked for Accuracy/Intervals (Mfct Rec or Opr Sched) **Annual calibration**	X			
172.	480-93-110(5)	Casings inspected/tested annually not to exceed fifteen months **None**			X	
173.	480-93-110(5)(a)	Casings w/no test leads installed prior to 9/05/1992. Demonstrate other acceptable test methods **None**			X	
174.	480-93-110(5)(b)	Possible shorted conditions – Perform confirmatory follow-up inspection within 90 days **None**			X	
175.	480-93-110(5)(c)	Casing shorts cleared when practical **None**			X	
176.	480-93-110(5)(d)	Shorted conditions leak surveyed within 90 days of discovery. Twice annually/7.5 months **None**			X	
177.	192.491	Interference Currents .473 **None**			X	
178.	192.491	Internal Corrosion; Corrosive Gas Investigation .475(a) **No corrosive gas**			X	
179.	192.491	Internal Corrosion; Internal Surface Inspection; Pipe Replacement .475(b) **None**			X	
180.	192.491	Internal Corrosion; New system design; Evaluation of impact of configuration changes to existing systems .476(d) **None**			X	
181.	192.491	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**) .477 **No coupons**			X	
182.	192.491	Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**) .481 **Performed every quarter for 2011 and 1st half of 2012, 2010 from CNG records.**	X			
183.	192.491	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions .483/.485 **None**			X	

Comments:

PIPELINE INSPECTION (Field)			S	U	N/A	N/C
184.	192.161	Supports and anchors	X			
185.	192.179	Valve Protection from Tampering or Damage	X			
186.	480-93-015(1)	Odorization levels	X			
187.	192.463	Levels of Cathodic Protection	X			
188.	192.465	Rectifiers DO 8 AM ON THURSDAY, CHECK RECTIFIER.	X			
189.	192.467	CP - Electrical Isolation	X			
190.	192.469	Test Stations (Sufficient Number)	X			
191.	192.476	Systems designed to reduce internal corrosion **Pipeline completed in 2000**			X	
192.	192.479	Pipeline Components Exposed to the Atmosphere	X			

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		PIPELINE INSPECTION (Field)	S	U	N/A	N/C
193.	192.481	Atmospheric Corrosion - monitoring	X			
194.	480-93-115(2)	Casings – Test Leads (Casings w/o vents installed after 9/05/1992) **None**			X	
195.	192.605	Knowledge of Operating Personnel	X			
196.	613(b), .703	Pipeline condition, unsatisfactory conditions, hazards, etc.	X			
197.	480-93-124	Pipeline Markers, Road and Railroad Crossings	X			
198.	192.719	Pre-pressure Tested Pipe (**Markings and Inventory**) **None, will test as required.**	X			
199.	192.739	Pressure Limiting and Regulating Devices (**Mechanical**) (spot-check field installed equipment vs. inspection records)	X			
200.	192.743	Pressure Limiting and Regulating Devices (**Capacities**) (spot-check field installed equipment vs. inspection records)	X			
201.	192.745	Valve Maintenance	X			
202.	192.751	Warning Signs Posted	X			
203.	192.801 - 192.809	Operator qualification questions – Refer to OQ Field Inspection Protocol Form	X			

Operator Qualification Field Validation

Important: Per PHMSA, the OQ Field Inspection Protocol Form 15 (Rev 3, Feb 08) shall be used by the inspector as part of this standard inspection. When completed, the inspector will upload this information into the PHMSA OQ Database (OQDB) located at http://primis.phmsa.dot.gov/oqdb/home.oq **Date Form Upload Completed:** 9/13/2012

Comments:

COMPRESSOR STATIONS INSPECTION **No compressors in system.** (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	
(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	

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COMPRESSOR STATIONS INSPECTION <u>**No compressors in system.**</u> (Note: Facilities may be "Grandfathered") If not located on a platform check here and skip 192.167(c)		**S**	**U**	**N/A**	**N/C**
	- 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	
.616	Public Awareness Program effectiveness - Visit identified stakeholders as part of field inspection routine			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:

Comments:

Alternative Maximum Allowable Operating Pressure
Lamb Weston/BSW does not use Alternative MAOP

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

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192.620	Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
	(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	
	(ii) Filter separators if needed			X	
	(iii) Gas Monitoring equipment used			X	
	(iv) Cleaning pigs, inhibitors, and sample accumulated liquids				
.620(d)	(v) Limit CO_2, H_2S, 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	

192.620	Alternative MAOP Procedures and Verifications	S	U	N/A	N/C
	(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	
	(1) Provide overpressure protection to a max of 104% MAOP			X	
.620(e)					
	(2) Procedure for establishing and maintaining set points for SCADA			X	

Comments:

Lamb Weston/BSW does not use Alternative MAOP

Recent Gas Pipeline Safety Advisory Bulletins: (Last 2 years)

Number	Date	Subject
ADB-09-01	May 21, 2009	Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe
ADB-09-02	Sept 30, 2009	Weldable Compression Coupling Installation
ADB-09-03	Dec 7, 2009	Operator Qualification Program Modifications
ADB-09-04	Jan 14, 2010	Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-10-02	Feb 3, 2010	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	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

Comments: