Utilities and Transportation Commission
Standard Inspection Report for Intrastate Hazardous Liquid Systems
Procedures and Plan Review

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.

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

Inspection Report			
Inspection ID/Docket #	5820		
Inspector Name & Submit Date	Dennis Ritter 12/17/2014		
Chief Engineer Name & Review Date	Joe Subsits, 12/31/2014		
Operator Information			
Name of Operator:	AltaGas Facilities, Inc	**OPID #:**	31758
Name of Unit(s):	Headquarters		
Records Location:	Ferndale, WA		
Date(s) of Last (unit) Inspection:	May 7-9, 2013 (Chevron was operator-OPID 2731)	**Inspection Date(s):**	December 1-4, 2014

Inspection Summary:

Arrived on site 12/1/14, 1 pm

This is a technical assistance visit. AltaGas is a new operator in the state of WA. They purchased the Ferndale Storage Terminal from Chevron in May, 2014. The Ferndale Storage Terminal is located in Ferndale, WA adjacent to the Conoco Phillips refinery at the end of Unick Road. It serves primarily as an HVL storage facility. There is some non-jurisdictional propane that is also transported by truck and rail from the facility. Currently, they primarily store and transport butane, however, there are plans to store propane in one tank and butane in the other. There are two storage tanks, designed to API 620 R specifications. Per the last WUTC audit in 2013 when Chevron was the operator, Tank T1 was required to undergo its 20-year API 653 inspection. This inspection was ongoing during this visit. Tank T1 was constructed in 1977 and has a capacity of 350,000 bbls. Tanks T2 was constructed in 1994 and has a capacity of 400,000 bbls. There is a jurisdictional pipeline in above and underground sections. The line starts at the inlet flange to the motorized valves at the termination of two 6-inch lines from the Conoco Phillips refinery. These lines run into the facility under Unick Rd.-approximately 30 feet is underground in a casing. The rest of the pipeline is above ground. There is also a connection to BP's 6-inch butane line from the Cherry Point refinery which terminates inside the facility. This line is operated by BP. Once inside the facility, the regulated lines run to both Tank 1 and 2. The turnaround, currently underway, added a separate drain line from Tank 1. This line is a regulated line per 49 CFR 195 and constructed accordingly. **It, and the rest of the regulated pipeline system, will be inspected (records and field) during the next formal audit.**

The primary purpose of the visit is to go through the checklists associated with the 195.402 procedural manual for operations and maintenance and emergencies (manual). Additionally, the drug and alcohol program was evaluated. Note, the operator qualification program was inspected by Ronda Shupert, WUTC, on November 2014 and found satisfactory. As such it was not evaluated. In general, in going through AltaGas' manual, deficiencies found were corrected on the master copy during the inspection. Issues which were not able to be corrected during the inspection are as follows:

1) **195.440 Public Awareness**-Currently, AltaGas does not have a public awareness plan meeting the requirements of 195.440. They do belong to the one-call system in Whatcom County. AltaGas is unique as a hazardous liquid pipeline operator in that they only have 30-feet of pipeline which is outside of their secure facility. The 40 acre facility is bounded as follows: Conoco Phillips refinery to the south, Intalco Aluminum Smelter to the north, Strait of Georgia to the west. The closest general public neighbor is approximately 6500 feet east. As such it is difficult to apply API 1162 to this operator. Given this, AltaGas is requesting the use of a modified program and/or be included in Conoco Phillips PA program. AltaGas will confer with Conoco Phillips to see if this approach would work. If not, they will propose a plan which they believe meets the intent of the code language while making sense for their facility and keeping the public informed and aware.

2) **195.442 Damage Prevention**-- AltaGas does not have a damage prevention plan meeting the requirements of 195.442. They do belong to the one-call system in Whatcom County. AltaGas believes they fall under the exemption under 195.442(d) as follows:

(d) A damage prevention program under this section is not required for the following pipelines:

(2) Pipelines to which access is physically controlled by the operator.

AltaGas contends that as the only accessible portion of their pipeline is the 30 feet road crossing adjacent to their main gate, that it is always under their control via gate guards or camera surveillance from their control room which is staffed 24/7. AltaGas must still meet

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the state requirements under WAC 480-75-270 and RCW 19.22.035.

3) **195.406 Maximum Operating Pressure**—AltaGas needs to amend the manual to indicate how they determine the MOP for their pipeline and include a calculation of the actual MOP per 195.406. This document could not be found during the inspection and AltaGas is having an engineer re-create it. AltaGas could not locate original hydrotest records for their pipeline. They are conferring with the former operator, Chevron to see if they can be found. It may be that AltaGas will need to re-hydrotest their pipeline.

4) **49 U.S.C. 60132,Subsection (b)ADB-08-07**-Required Submission of Data to the National Pipeline Mapping System Under the Pipeline Safety Improvement Act of 2002. AltaGas amended its manual to ensure an annual submission, however, they also need to send updated mapping to NPMS as the current mapping shown in PIMMA does not include the regulated pipe to and from the tanks, T1 and T2.

5) **RCW 81.88.080-Pipeline Mapping System—**AltaGas believes the MOP of their pipeline will be over 250 psi. As such, they will need to submit mapping to the WUTC.

6) **PART 199 – DRUG and ALCOHOL TESTING REGULATIONS and PROCEDURES-**In evaluating the current AltaGas Drug and Alcohol Plan, it became apparent that significant improvements to the plan were necessary. Examples of other drug and alcohol plans were reviewed showing the necessary language required in the plan. AltaGas is going to revise their entire plan. **This will be reviewed during the next formal audit.**

7) <u>WAC 480-75-660 Procedureal Manual for Operations, Maintenance, and Emergencies</u>

AltaGas has not submitted its procedural manual (O&M manual) per 480-75-660(2). During the inspection, AltaGas was informed of this requirement and what constitutes their O&M manual. AltaGas must submit these documents to the WUTC by January 31, 2015.

HQ Address:	**System/Unit Name & Address:**
SEMCO ENERGY Gas Company 1411 Third Street, Suite A Port Huron, MI 48060	AltaGas Ferndale Storage Terminal 4100 Unick Rd Ferndale, WA 98248

Co. Official:	Steve Warsinske	**Phone No.:**	360-384-1701
Phone No.:	810-887-4720	**Fax No.:**	360- 384-7044
Fax No.:		**Emergency Phone No.:**	360-384-1701
Emergency Phone No.:			

Persons Interviewed	Title	Phone No.
Gary McSpadden	Maintenance Coordinator	360-384-1701
Andrew Gamble	Operations Manager	360-380-8510
Robert McCoy	Project Coordinator	360-3841701
Michelle Smith	Principal Consultant, ERM	360-647-3900
Michelle Fisher	Consultant, ERM	360-296-6135
June Coover	Partner, ERM	

CONVERSION TO SERVICE			S	U	N/A	N/C
1.	**195.5(a-c)**	Has a written procedure been developed addressing all applicable requirements and followed? No conversions.			X	

REGULATED RURAL GATHERING LINES **No gathering lines**			S	U	N/A	N/C
2.	**195.11**	Operator has identified pipelines that are Regulated Rural Gathering Lines that meet all of the following criteria: (1) nominal diameter from 6 5/8 inches to 8 5/8 inches; (2) located in or within one-quarter mile of a USA (3) operates at an MOP established under §195.406 that is: (i) greater than 20% SMYS; or (ii) if the stress level is unknown, or not steel; > 125 psig.			X	
3.	**195.11(b)**	Operator has prepared written procedures to carry out the requirements of **195.11.** • Subpart B Reporting • Corrosion Control • Damage Prevention • Public Awareness • Establish MAOP • Line Markers • Operator Qualification			X	
4.	**195.11(c)**	If a new USA is identified after July 3, 2008, the operator must implement the requirements in paragraphs (b)(2 - 8), and (b)(11) for affected pipelines within 6 months of identification. For steel pipelines, comply with the deadlines in paragraphs (b)(9 & 10).			X	
5.	**195.11(d)**	Operator must maintain : (1) Segment identification records required in paragraph (b)(1) of this section and the records required to comply with (b)(10) of this section, for the life of the pipe. (2) records necessary to demonstrate compliance (b)(2 – 9 & 11) of this section according to the record retention requirements of the referenced section or subpart.			X	

Comments:

LOW-STRESS PIPELINES IN RURAL AREAS No low stress rural pipelines			S	U	N/A	N/C
6.	**195.12(a)**	Operator has identified pipelines that are Regulated Low-stress Pipelines in Rural Areas that meet all of the following criteria: (except for those already covered by 49 CFR 195) (1) nominal diameter of 8 5/8 inches or more; (2) located in or within one-half mile of a USA (3) operates at an MOP established under §195.406 that is: (i) greater than 20% SMYS; or (ii) if the stress level is unknown, or not steel; > 125 psig.			X	
7.	**195.12(b)**	Operator has prepared written procedures to carry out the requirements of **195.12.** • Subpart B Reporting • Establish Integrity Management Plan • All Part 195 Safety Requirements			X	
8.	**195.12(c)(1)**	Operator may notify PHMSA of economic burden.			X	
9.	**195.12(d)**	If, after July 3, 2008, a new USA is identified, the operator must implement the requirements in paragraphs (b)(2)(i) for affected pipelines within 12 months of identification.			X	
10.	**195.12(d)**	Operator must maintain: (1) Segment identification records required in paragraph (b)(1) for the life of the pipeline. (2) Records necessary to demonstrate compliance (b)(2 - 4)according to the record retention requirements of the referenced section or subpart.			X	

Comments:

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
11.	**195.402(a)** **195.402(c)(2)**	Complete and submit DOT Form PHMSA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year for each commodity, and each state a pipeline traverses by June 15 of each calendar year. ***(NOTE: August 15, 2011 for the year 2010)***. (Amdt. 195-95, 75 FR 72877, November 26, 2010, eff. 1/1/2011). **.49 Section 7.8 of OQ and Pipeline System Facility Manual**	X			
12.		Accident report criteria, as detailed under 195.50. A release that results in, **5 gallons** or more, **death or personal injury necessitating hospitalization**, an **explosion or fire not intentionally set by the operator**, or total estimated property damage including clean-up and product lost equaling **$50,000** or more. (Note: A release of less than 5 gals may still require reporting. See 195.50(b) and 195.52(a)(4) for additional requirements and exemptions for maintenance work under 5 BBLS). **.50 Section 7.4**	X			
13.		Immediate notice to **NRC (800) 424-8802,** or electronically at **http://www.nrc.uscg.mil**, of certain events, 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. 195-95, 75 FR 72878, November 26, 2010, eff. 1/1/2011). **.52 Appx F 1.0 Estimating Release quantity; Appx H –phone list**	X			
14.		Accident Report - file as soon as practicable, but no later than 30 days after discovery. Submittal must be electronically to **http://pipelineonlinereporting.phmsa.dot.gov** Note this is an outdated web address should be-https://portal.phmsa.dot.gov/portal (Amdt. 195-95, 75 FR 72878, November 26, 2010). **.54(A)Section 7.5**	X			
15.		Supplemental report - required within 30 days of information change/addition **.54(b) Section 7.5**	X			

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
16.		Safety-related conditions (SRC) - criteria **.55** **Section 7.2, looked at MIP 102**	X			
17.		SRC Report is required to be filed within five **(5)** working days of the determination and within ten **(10)** working days after discovery **.56(a)**	X			
18.		SCR Report requirements, including corrective actions (taken and planned) **.56(b)** **Maintenance and Inspection Procedure (MIP) 102.5.6.3**	X			
19.	**195.402(a)** **195.402(c)(2)**	Reports (except SRCR and offshore pipeline condition reports) must be submitted electronically to PHMSA at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized IAW with paragraph (d) of this section. (Amdt. 195-95, 75 FR 72878, Nov. 26, 2010, eff. 1/1/2011)..	X			
20.		Each operator must obtain an OPID, validate its OPIDs, and notify PHMSA of certain events at http://portal.phmsa.dot.gov/pipeline (Amdt. 195-95, 75 FR 72878, Nov.26, 2010, eff. 1/1/2011). **.64(a-d)**	X			
		WAC 480-75 REPORTING PROCEDURES	**S**	**U**	**N/A**	**N/C**
21.	**480-75-610**	Reporting of proposed pipeline construction 45 days prior to construction Section 4.5	X			
22.	**480-75-620**	Providing notice of hydrotest to change MOP MIP 301.12.3	X			
23.	**480-75-630**	Telephonic Reports to **UTC Pipeline Safety Incident Notification 1-888-321-9144** (Within **2 hours of discovery**) for events which results in; Section 7.4 a) A fatality; (b) Personal injury requiring hospitalization; (c) Fire or explosion not intentionally set by the pipeline company; (d) Spills of five gallons or more of product from the pipeline; (e) Damage to the property of the pipeline company and others of a combined total cost exceeding twenty-five thousand dollars (automobile collisions and other equipment accidents not involving hazardous liquid or hazardous-liquid-handling equipment need not be reported under this rule); (f) A significant occurrence in the judgment of the pipeline company, even though it does not meet the criteria of (a) through (e) of this subsection; (g) The news media reports the occurrence, even though it does not meet the criteria of (a) through (f) of this subsection.	X			
24.	**480-75-630(2)**	Written reports to the commission within 30 calendar days of the incident. The report must include the following: Section 7.5 a) Name(s) and address(es) of any person or persons injured or killed or whose property was damaged; (b) The extent of injuries and damage; (c) A description of the incident including date, time, and place; (d) A description and maximum operating pressure of the pipeline implicated in the incident and the system operating pressure at the time of the incident; (e) The date and time the pipeline returns to safe operations; and (f) The date, time, and type of any temporary or permanent repair.	X			
25.	**480-75-630(3)**	Notification within **24 hours** of emergency situations including emergency shutdowns, material defects or physical damage that impairs serviceability? Section 7.6	X			
26.	**480-75-630(4)**	**Filing Reports of Damage to Hazardous Liquid Pipeline Facilities to the commission. (eff. 4/1/2013)** **(**Via the commission's Virtual DIRT system or on-line damage reporting form)				
27.	**480-75-630(4)(a)**	Does the operator report to the commission the requirements set forth in RCW 19.122.053(3) (a) through (n) Section 7.7.1	X			
28.	**480-75-630(4)(b)**	Does the operator report the name, address, and phone number of the person or entity that the company has reason to believe may have caused damage due to excavations conducted without facility locates first being completed? Section 7.7.1	X			
29.	**480-75-630(4)(c)**	Does the operator retain all damage and damage claim records it creates related to damage events reported under 93-200(7)(b), including photographs and documentation supporting the conclusion that a facilities locate was not completed? **Note:** Records maintained for two years and made available to the commission upon request. Section 7.7.1	X			
30.	**480-75-630(5)**	Does the operator provide the following information to excavators who damage hazardous liquid pipeline facilities? Section 7.7.2				
31.	**480-75-630(5)(a)**	• Notification requirements for excavators under RCW 19.122.050(1) Section 7.7.2	X			
32.	**480-75-630(5)(b)**	• A description of the excavator's responsibilities for reporting damages under RCW 19.122.053; and Section 7.7.2	X			

SUBPART B - REPORTING PROCEDURES			S	U	N/A	N/C
33.	**480-75-630(5)(c)**	• Information concerning the safety committee referenced under RCW 19.122.130, including committee contact information, and the process for filing a complaint with the safety committee. Section 7.7.2	X			
34.	**480-75-630(6)**	**Reports to the commission only when the operator or its contractor observes or becomes aware of the following activities…Section 7.73** • An excavator digs within thirty-five feet of a transmission pipeline, as defined by RCW 19.122.020(26) without first obtaining a facilities locate; (630(6)(a) • A person intentionally damages or removes marks indicating the location or presence of hazardous liquid pipeline facilities. 630(6)(b)	X			

Comments:

SUBPART C – INTERNAL DESIGN PRESSURE PROCEDURES			S	U	N/A	N/C
35.	**195.402(c)** **195.422**	Internal design pressure for pipe in a pipeline is determined in accordance with the requirements of this section and the formula: P = (2 St/D) x E x F. **.106 APPX C**	X			

SUBPART C - PASSAGE OF INTERNAL INSPECTION DEVICE PROCEDURES			S	U	N/A	N/C
36.	**195.402(c)** **195.422**	Each new pipeline or each section of a pipeline which pipe or components has been replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices that are applicable to this section **.120(a)** Section 2.1.1 MIP 403, 5.1.5	X			

Comments:

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
Compliance with welding requirements for pipe replaced or repaired in the course of pipeline maintenance is required by §195.422 and §195.200.						
37.	**195.402(c)** **195.422**	Welding must be performed by qualified welders using qualified welding procedures. **.214(a) MIP 407**	X			
38.		Are welding procedures qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code? MIP 407	X			
39.		Welding procedures must be qualified by destructive testing. MIP 407 APPX D	X			
40.		Each welding procedure must be recorded in detail including results of qualifying tests. **.214(b)** section 2.4, MIP 407 APPX A	X			
41.		Welders must be qualified in accordance with **Section 6 of API Standard 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 **195.3** may weld, but may not re-qualify under that earlier edition. (Amdt 195-94 Pub. 8/11/10 eff. 10/01/10). **.222(a) MIP 407**	X			

SUBPART D – WELDING, NDT, and REPAIR /REMOVAL PROCEDURES			S	U	N/A	N/C
42.		Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has--(1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104. **.222(b)** **MIP 407 Appx B.**	X			
43.	**195.402(c)** **195.422**	Arc burns must be repaired. **.226(a)** **MIP 407.5.11.2**	X			
44.		Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**. Pipe must be removed for non-repairable notches. **.226(b)** **MIP 407.5.11.2**	X			
45.		The ground wire may not be welded to the pipe/fitting being welded. **.226(c) MIP 407.5.8.5**	X			
Nondestructive Testing Procedures						
46.	**195.402(c)** **195.422**	Do procedures require welds to be nondestructively tested to ensure their acceptability according to **API 1104** and as per **195.228(b)** and per the requirements of **195.234** in regard to the number of welds to be tested? **MIP 407.5.10**	X			
47.		Nondestructive testing of welds must be performed: **.234(b)**				
48.		1. In accordance with written procedures for **NDT** **MIP 407.5.10.3**	X			
49.		2. By qualified personnel **MIP 407.5.10.9**	X			
50.		3. By a process that will indicate any defects that may affect the integrity of the weld **MIP 407.5.10**	X			
51.		Records of the total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld, must be maintained. **.266** **100% MIP 407.5.10**	X			
Repair or Removal of Weld Defect Procedures						
52.	**195.402(c)** **195.422**	Welds that are unacceptable must be removed and/or repaired. See **.228** and **.230** for exceptions. **.230** **MIP 407.5.11**	X			

Comments:

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
53.	**195.402(c)** **195.422** **480-93-420**	Pipelines, and each pipeline segment that has been relocated, replaced, or otherwise changed, must be pressure tested without leakage (see .302(b), (c), and .305(b) for exceptions). **.302(a)** **MIP 301 Section 4.0**	X			
54. **55.** **56.** **57.**		Except for lines converted under **§195.5**, the following pipelines may be operated without having been pressure tested per Subpart E and without having established MOP under **195.406(a)(5)** [80% of the 4 hour documented test pressure, or 80% of the 4 hour documented operating pressure] .302(c) - Intrastate liquid lines constructed before 10/21/85 (excluding HVL onshore or low stress lines). .302(b)(iii) - Carbon dioxide pipeline constructed before 07/12/91 that is located in a rural area as part of production field distribution system. .302(b)(2)(ii) - Any low-stress pipeline constructed before 8/11/1994, that does not transport HVL. .302(b)(3) - Those portions of older hazardous liquid and carbon dioxide pipelines for which an operator has elected the risk-based alternative under §195.303 and which are not required to be tested based on the risk-based criteria. .302(b)(4)/.303 ***Note:*** *(An operator that elected to follow a risk-based alternative must have developed plans that included the method of testing and a schedule for the testing by December 7, 1998. The compliance deadlines for completion of testing are as shown in the table in §195.303, and in no case was testing to be completed later than 12/07/2004).*				
58.		Have pipelines other than those described above been pressure tested per Subpart E?		X		

SUBPART E - PRESSURE TESTING PROCEDURES			S	U	N/A	N/C
59.		If pipelines <u>other than those described above</u> have not been pressure tested per Subpart E, has MOP been established under **195.406(a)(5),** in accordance with **.302(c)?** See Maximum Operating Pressure below. ***Note:*** *Establishing MOP under 195.406(a)(5) only applies to specified "older" pipelines constructed prior to the dates in .302(b).*		X		
60.		Test pressure must be maintained for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected during the test, at least an additional 4 hours at 110 percent of MOP is required. **.304 MIP 301 Section 10.2**	X			
61.		All pipe, all attached fittings, including components, must be pressure tested in accordance with **§195.302**. **.305(a) MIP 301 Section 4.0**	X			
62.		A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either: (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory. **.305(b)) Section 4.14**	X			
63.		Appropriate test medium **.306 MIP 301 Section 10**	X			
64.		Pipe associated with tie-ins must be pressure tested. **.308 MIP 301 Section 4.0**	X			
65.		Test records must be retained for useful life of the facility. **.310(a) MIP 301 Section 13.3**	X			
		Does the record required by paragraph **(a)** of this section include: **.310(b) MIP 301 Section 10**				
66.		Pressure recording charts. **.310(b)(1) MIP 301 Section 10.10**	X			
67.		Test instrument calibration data. **.310(b)(2) MIP 301 Section 10.10**	X			
68.		Name of the operator, person responsible, test company used, if any. **.310(b)(3) MIP 301 Section 10.10**	X			
69.		Date and time of the test. **.310(b)(4) MIP 301 Section 10.10**	X			
70.		Minimum test pressure. **.310(b)(5) MIP 301 Section 10.10**	X			
71.		Test medium. **.310(b)(6) MIP 301 Section 10.10**	X			
72.		Description of the facility tested and the test apparatus. **.310(b)(7) MIP 301 Section 10.10**	X			
73.		Explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts. **.310(b)(8) MIP 301 Section 10.10**	X			
74.		Where elevation differences in the test section exceed **100 feet**, a profile of the elevation over entire length of the test section must be included **.310(b)(9) MIP 301 Section 10.10**	X			
75.		Temperature of the test medium or pipe during the test period. Amdt 195-78 pub. 9/11/03, eff. 10/14/03. **.310(b)(10) MIP 301 Section 10.10**	X			
76.		Signature of certifying agent. **WAC 480-75-420 (4)(b) MIP 301 Section 10.10**	X			
77.		Beginning and ending times of the test. **WAC 480-75-420 (4)(c) MIP 301 Section 10.10**	X			
78.		Highest and lowest pressure achieved. **WAC 480-75-420 (4)(e) MIP 301 Section 10.10**	X			
79.		Is report submitted to the commission 45 days prior to a hydro test, if test was used to raise the MOP (after 9/26/02)? **WAC 480-75-620 MIP 301 Section 10.10**	X			

Comments:

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES	S	U	N/A	N/C

SUBPART F - OPERATIONS & MAINTENANCE PROCEDURES				S	U	N/A	N/C
80.	**195.402(a)**	a.	Has the operator prepared a manual for normal operations & maintenance activities & handling abnormal operations & emergencies? **.402** Revision 0, 11/09/14	X			
81.		b.	Procedures for reviewing the manual at intervals not exceeding 15 months, but at least each calendar year? Section 1.3-Might want to define "significant changes". Significant changes require MOC. Revision 0, 11/09/14	X			
82.		c.	Appropriate parts must be kept at locations where O&M activities are conducted. Control Room contains master copy. Master copy is kept in control room.	X			

Comments:

SUBPART F - MAINTENANCE & NORMAL OPERATION PROCEDURES			S	U	N/A	N/C
	195.402(a)	Written procedures must be **followed** to provide safety during maintenance and normal operations. Does the operator have procedures for: **.402(c)**				
83.		Determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned? **.402(c)(4)** Section 6.3	X			
84.		Analyzing pipeline accidents to determine their causes? **.402 (c)(5)Section 8.6.2**	X			
85.		Minimizing the potential for hazards identified under paragraph **(c)(4)** and minimizing the possibility of recurrence of accidents analyzed under paragraph **(c)(5)**? **.402(c)(6) section 6.3**	X			
86.		Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within limits prescribed by **§195.406**, considering the hazardous liquid or carbon dioxide in transportation, variations in the altitude along the pipeline, and pressure monitoring and control devices? **.402(c)(7) Section 4.8 and 4.9 MOP 2.1.6**	X			
87.		A pipeline that is not equipped to fail safe monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by **§195.406**? **.402(c)(8) Do monitor start up and shut down. Section 4.8, 4.9**	X			
88.		Facilities not equipped to fail safe that are identified under **§195.402(c)(4)** or that control receipt and delivery of hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location? **.402(c)(9) Section 5.7**	X			
89.		Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned environmental hazards **.402(c)(10) no abandoned pipelines**			X	
90.		Reporting abandoned pipeline facilities offshore, or onshore crossing commercially navigable waterways per 195.59. **no abandoned pipelines**			X	
91.		Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph **(c)(4)** of this section where the potential exists for the presence of flammable liquids or gases? **.402(c)(11) Section 4.12**	X			
92.		Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each hazardous liquid pipeline emergency. **.402(c)(12) Section 6.4 Coast Guard, FD 7 & 11, Alcoa, mock drills**	X			
93.		Periodically reviewing the work done by operator's personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found? **.402(c)(13) Section 8.6**	X			
94.		Taking adequate precautions in excavated trenches to protect personnel from hazards of unsafe accumulations of vapor or gas, making available when needed at the excavation site, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line. **.402(c)(14) Section 4.11, 12**	X			

Comments:

Comments:

MAINTENANCE & NORMAL OPERATION PROCEDURES CONT:			S	U	N/A	N/C
95.	**.402(c)(15)**	Implementing the applicable control room management procedures required by **195.446.** (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010). **.402(c)(15) Section 8.2, Appx I**			X	
96.	**480-75-300**	Providing leak detection under flow and no flow conditions and including a procedure for responding to alarm Section 2.5 facility does have hydrocarbon sensors	X			
97.	**480-75-330**	Responding to breakout tank overfill alarms Section 4.13	X			
98.	**480-75-400**	Backfilling pipe Appendix T and MIP 409	X			
99.	**480-75-410**	Using a holiday detector to check coating condition prior to backfilling Section 2.3.1	X			
100.	**480-75-460**	100% Inspection of welds.	X			
101.	**480-75-550**	Reviewing change in class location for pipelines installed after 9/26/2003. Section 3.9.2.4			X	

ABNORMAL OPERATION PROCEDURES (CONTROL CENTER FUNCTION)				S	U	N/A	N/C
	195.402(a)	The O&M manual must contain written procedures to provide safety when operating design limits have been exceeded. Does the operator have procedures for: **.402(d)**					
		Responding to, investigating, and correcting the cause of: **.402(d)(1)**					
102.		i.	Unintended closure of valves or shutdowns? Section 5.5	X			
103.		ii.	An increase or decrease in pressure or flow rate outside normal operating limits? Section 5.6	X			
104.		iii.	Loss of communications? Section 5.7	X			
105.		iv.	The operation of any safety device? Section 5.8	X			
106.		v.	Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property? Section 5.9	X			
107.		Checking variations from normal operation after abnormal operations have ended at sufficient critical locations in the system to determine continued integrity and safe operations? **.402(d)(2)** Section 5.10		X			
108.		Correcting variations from normal operation of pressure and flow equipment controls? **.402(d)(3)** Section 5.10		X			
109.		Does operating personnel notify responsible operator personnel where notice of an abnormal operation is received? **.402(d)(4)** Section 6.2		X			
110.		Periodically reviewing the response of operating personnel to determine the effectiveness of the procedures and taking corrective action where deficiencies are found? **.402(d)(5)** Section 8.6.1		X			

Comments:

EMERGENCY PROCEDURES			S	U	N/A	N/C
		The O&M manual must include written procedures to provide safety when an emergency condition occurs. Does the operator have procedures for: **.402(e)**				

EMERGENCY PROCEDURES			S	U	N/A	N/C
111.	**195.402(a)**	Receiving, identifying, and classifying notices of events which need immediate response by the operator or fire, police, or other, and notifying appropriate operator's personnel for corrective action? **.402(e)(1)** Section 6.2 **Note:** Including third-party damage	X			
112.		Making a prompt and effective response to a notice of each type of emergency, fire, explosion, accidental release of hazardous liquid, operational failure, natural disaster affecting the pipeline? **.402(e)(2)** Section 6.3, 6.5, 6.6 **Note:** Including third party damage	X			
113.	**195.402(a)**	Making personnel, equipment, instruments, tools, and materials available at the scene of an emergency? **.402(e)(3)** Section 6.7	X			
114.		Taking action; such as emergency shutdown or pressure reduction, to minimize release of liquid at a failure site? **.402(e)(4)** Section 6.5, 6.6	X			
115.		Controlling the release of liquid at the failure site? **.402(e)(5)** Section 6.5, 6.3	X			
116.		Minimizing the public **.402(e)(6)**exposure and accidental ignition, evacuation, and halting traffic on roads, railroads, etc.? Section 6.5, 6.6	X			
117.		Notifying fire, police, and others of hazardous liquid emergencies and preplanned responses including **HVLs**? **.402(e)(7)** Section 6.3	X			
118.		Determining extent and coverage of vapor cloud and hazardous areas of **HVLs** by using appropriate instruments? **.402(e)(8)** Section 6.8	X			
119.		Post-accident review of employee's activities to determine if procedures were effective and corrective action was taken? **.402(e)(9)** Section 8.6.2	X			
120.		Actions to be taken by a controller during an emergency in accordance with **195.446.** (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010). **.402(e)(10)** Section 6.3, 6.5	X			

Comments:

EMERGENCY RESPONSE TRAINING PROCEDURES (CONTROL CENTER & FIELD)			S	U	N/A	N/C
		Each operator shall establish and conduct a written continuing training program to instruct operating and maintenance personnel to: **.403(a)**				
121.		Carry out the emergency response procedures established under §195.402. **.403(a)(1)** **Section 1.2, Section 8, Emergency Response Plan-August 2014**	X			
122.		Know the characteristics and hazards of liquids or carbon dioxide transported, including in the case of **HVL**, flammability, of mixtures with air, odorless vapors, and water reactions. **.403(a)(2)** **, Section 8, Emergency Response Plan-August 2014**	X			
123.		Recognize conditions that are likely to cause emergencies; predict the consequences of malfunction or failures and take appropriate actions. **.403(a)(3)** **, Section 8, Emergency Response Plan-August 2014**	X			
124.	**195.402(a)**	Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage. **.403(a)(4)** **, Section 8, Emergency Response Plan-August 2014**	X			
125.		Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition. **.403(a)(5)** **, Section 8, Emergency Response Plan-August 2014**	X			
126.		Instructions to enable O&M personnel to recognize and report potential safety related conditions. **.402(f)** **, Section 8, Emergency Response Plan-August 2014**	X			
		At intervals not exceeding 15 months, but at least once each calendar year: **.403(b)**				
127.		Review with personnel their performance in meeting the objectives of the emergency response training program **.403(b)(1)** **Section 8.6.2**	X			
128.		Make appropriate changes to the emergency response training program **.403(b)(2)**	X			
129.		Require and verify that supervisors maintain a thorough knowledge of the emergency response procedures for which they are responsible. **.403(c)** **Section 8.0**	X			

Comments:

		MAPS and RECORDS PROCEDURES	S	U	N/A	N/C
130.	195.402(a) & WAC 480-75-600	Making construction records, maps, and operating history available as necessary for safe operation and maintenance. **.402(c)(1)** **Section 4.17**	X			
		Each operator shall maintain current maps and records of its pipeline system that include at least the following information: **.404(a)** Updated within 6 months **480-75-600**				
		Location and identification of the following facilities: **.404(a)(1)** **Plot plans D-3000-72-001,002,003,004**				
131.		i. Breakout tanks	X			
132.		ii. Pump stations	X			
133.		iii. Scraper and sphere facilities	X			
134.		iv. Pipeline valves	X			
135.		v. Facilities to which **§195.402(c)(9)** applies			X	
136.		vi. Rights-of-way	X			
137.		vii. Safety devices to which **§195.428** applies Note these are found on individual P&ID sheets	X			
138.		All crossings of public roads, railroads, rivers, buried utilities and foreign pipelines. **.404(a)(2)**	X			
139.		The maximum operating pressure of each pipeline. **.404(a)(3)** **Section 4.17**	X			
140.		The diameter, grade, type, and nominal wall thickness of all pipe. **.404(a)(4)** **Section 4.17**	X			
		Each operator shall maintain for at least **3 years** daily operating records for the following: **.404(b)**				
141.		The discharge pressure at each pump station. **.404(b)(1)** **Appx D**	X			
142.		Any emergency or abnormal operation to which the procedures under **§195.402** apply. **.404(b)(2)** **Appx D**	X			
		Each operator shall maintain the following records for the periods specified: **.404(c)**				
143.		The date, location, and description of each repair made on the pipe and maintain it for the **life of the pipe**. **.404(c)(1)** **Appx D**	X			
144.		The date, location, and description of each repair made to parts of the pipeline system other than the pipe and maintain it for at least **1 year**. **.404(c)(2)** **Appx D**	X			
145.		Each inspection and test required by **Subpart F** shall be maintained for at least **2 years, or until the next inspection or test is performed, whichever is longer**. **.404(c)(3)** **Appx D**	X			

Comments:

		MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS	S	U	N/A	N/C
	195.402(a)	Except for surge pressures and other variations from normal operations, the MOP may not exceed any of the following: **.406(a)**				
146.		The internal design pressure of the pipe determined by **§195.106**. Amt. 195-86 Pub. 06/09/06 eff. 07/10/06 **.406(a)(1)** **Section 2.1.6**	X			
147.		The design pressure of any other component on the pipeline. **.406(a)(2)**	X			
148.		**80%** of the test pressure **(Subpart E)**. **.406(a)(3)**	X			

MAXIMUM OPERATING PRESSURE PROCEDURES (MOP) - ALL SYSTEMS			S	U	N/A	N/C
149.		**80%** of the factory test pressure or of the prototype test pressure for any individual component. **.406(a)(4)**	X			
150.		**80%** of the test pressure or the highest operating pressure for a minimum of **4 hours** for a pipeline that has not been tested under **Subpart E**. **.406(a)(5)**	X			
151.		The pipeline may not be operated at a pressure that exceeds **110% of the MOP** during surges or other variations from normal operations: **.406(b)**	X			
152.		Adequate controls and protective equipment must be installed to prevent the pressure from exceeding **110%** of the **MOP**. Section 2.1.6.1	X			

Comments:
AltaGas could not locate original MOP records including hydrotest records for their pipeline. They are conferring with the former operator, Chevron to see if they can be found. It may be that AltaGas will need to re-hydrotest their pipeline.

COMMUNICATION PROCEDURES (CONTROL CENTER)			S	U	N/A	N/C
153.	**.402(a)**	Operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system. **.408(a)** **Section 2.4**	X			
		Does the communication system required by paragraph **(a)** include means for: **.408(b)**				
154.		Monitoring operational data as required by **§195.402(c)(9)**. **.408(b)(1)** **Section 2.4**	X			
155.		Receiving notices from operator personnel, the public, and others about abnormal or emergency conditions and initiating corrective actions. **.408(b)(2)** **Section 2.4**	X			
156.		Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies. **.408(b)(3)** **Section 2.4 Section 2.4**	X			
157.		Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster. **.408(b)(4)** **Section 2.4**	X			

Comments:

LINE MARKER PROCEDURES			S	U	N/A	N/C
158.	**480-75-540**	Markers checked annually and replaced within 30 days Section 4.2	X			
159.	**195.402(a)**	Line markers must be placed over each buried pipeline in accordance with the following: **.410(a)** Section 4.2	X			
160.		Located at each public road crossing, railroad crossing, and sufficient number along the remainder of each buried line so that its location is accurately known **.410(a)(1)** Section 4.2	X			
161.		Must have the correct characteristics and information **.410(a)(2)** Section 4.2	X			
162.		Must be placed where pipelines are aboveground in areas that are accessible to the public **.410(c)** Section 4.2	X			

Comments:

INSPECTION RIGHTS-of -WAY & CROSSINGS UNDER NAVIGABLE WATER PROCEDURES			S	U	N/A	N/C
163.	**480-75-540**	**Depth of Cover -** For pipelines constructed after 4/1/70, depth of cover surveys every five years or every three years for areas subject to erosion or subsoiling No water crossing.			X	
164.	**195.402(a)**	Operator must inspect the right-of-way weekly (unless weather impedes flyovers when applicable) **WAC 480-75-530** **Section 4.1**	X			
165.		Operator must inspect each crossing under a navigable waterway to determine the crossing condition at intervals not exceeding 5 **years**. **.412(b)** No water crossing.			X	

Comments:

UNDERWATER INSPECTION PROCEDURES of OFFSHORE PIPELINES			S	U	N/A	N/C
	195.402(a)	When the operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, does the operator: **.413(c)** No water crossing.				
166.		Promptly, but no later than 24 hours after discovery, notify the NRC by phone. **.413(c)(1)** No water crossing.			X	
167.		Promptly, but not later than **7 days** after discovery, mark the location of the pipeline in accordance with **33 CFR Part 64** at each end 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. **.413(c)(2)** No water crossing.			X	
168.		Within **6 months** after discovery, or not later than **November 1** of the following year if the **6 month** period is after **November 1** of that year the discovery is made, 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. **.413(c)(3)** No water crossing.			X	
169.		Offshore pipeline condition reports - must be filed within 60 days after the inspections **.57** No water crossing.			X	

Comments:

VALVE MAINTENANCE PROCEDURES			S	U	N/A	N/C
170.	**195.402(a)**	Operator must maintain each valve that is necessary for the safe operation of its pipeline system in good working order at all times. **.420(a)** **Section 4.10 MIP 802**	X			
171.		Operator must inspect each mainline valve to determine that it is functioning properly at intervals not exceeding **71/½ months**, but at least **twice** each calendar year. **.420(b)** **MIP 802.5.1**	X			
172.		Operator must provide protection for each valve from unauthorized operation and from vandalism. **.420(c)** **MIP 802.5.3**	X			

Comments:
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PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
173.	**WAC 480-75-440**	Repairs made in accordance with **ASME B31.4** Section 4.6, MIP 403.2.4	X			

PIPELINE REPAIR PROCEDURES			S	U	N/A	N/C
174.	**195.402(a)**	Operator must, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons and property. **.422(a)** Section 4.6, MIP 403 1.0 and 5.2	X			
175.		No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part. **.422(b)** Section 4.6, MIP 403 1.0 and 5.2	X			

Comments:

PIPE MOVEMENT PROCEDURES			S	U	N/A	N/C
176.	**480-75-500**	For evaluating pipe conditions during pipe movement including API 1117 stress calculations? Pipeline is short. They don't use this code. See regulatory correlation table in Manual and Section 4.15			X	
177.	**195.402(a)**	When moving any pipeline, the operator must reduce the pressure for the line segment involved to **50% of the MOP**. **.424(a)** Pipeline is short. They don't use this code. But will add to their cross reference list and Section 4.15			X	
		For **HVL** lines **joined** by welding, the operator must: **.424(b)** Pipeline is short. They don't use this code. See regulatory correlation table in Manual and Section 4.15				
178.		Move the line when it does not contain **HVL**, unless impractical. **.424(b)(1)**			X	
179.		Have procedures under **§195.402** containing precautions to protect the public. **.424(b)(2)**			X	
180.		Reduce the pressure for the line segment involved to the lower of **50% of the MOP** or the lowest practical level that will maintain the **HVL** in a liquid state. **(Minimum = V.P. + 50 psig) .424(b)(3)**	X			
		For **HVL** lines **not joined** by welding, the operator must: **.424(c)** **All welded pipeline.**				
181.		Move the line when it does not contain **HVL**, unless impractical. **.424(c)(1)**			X	
182.		Have procedures under **§195.402** containing precautions to protect the public. **.424(c)(2)**			X	
183.		Isolate the line to prevent flow of the **HVL**. **.424(c)(3)**			X	

Comments:

SCRAPER and SPHERE FACILITY PROCEDURES			S	U	N/A	N/C
184.	**195.402(a)**	Operator must have a relief device capable of safely relieving the pressure in the barrel before insertion or removal of scrapers or spheres. **.426** **EOHS 9.6**	X			
185.		Operator must have a suitable device to indicate that pressure has been relieved, or a means to prevent insertion. **EOHS 9.6**	X			

Comments:

OVERPRESSURE SAFETY DEVICE PROCEDURES	S	U	N/A	N/C

OVERPRESSURE SAFETY DEVICE PROCEDURES			S	U	N/A	N/C
186.	**195.402(a)**	Operator must inspect and test each pressure limiting device, relief valve, pressure regulator, or other items of pressure control equipment to determine that it is functioning properly, in good mechanical condition, has adequate capacity, and is reliable. **.428(a)** **Section 4.13**	X			
		Operator must inspect and test overpressure safety devices at the following intervals:				
187.		1. **Non-HVL** pipelines at intervals not to exceed **15 months**, but at least once each calendar year. Do have HVLs			X	
188.		2. **HVL** pipelines at intervals not to exceed **7-1/2 months**, but at least **twice** each calendar year.	X			
189.		Operator must inspect and test relief valves on HVL breakout tanks at intervals not exceeding **5 years**. **.428(b)** Section 4.13	X			
190.		Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Tanks over 600 gallons (2271 liters) constructed or significantly altered after October 2, 2000, must have overfill protection according to API Recommended Practice 2350 unless operator noted in procedures manual (§195.402) why compliance with API RP 2350 is not necessary for the safety of a particular breakout tank. **.428(c)** Have not had significant alternations.			X	
191.		After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems. **.428(d)** Have not had significant alternations.			X	

Comments:

FIREFIGHTING EQUIPMENT PROCEDURES			S	U	N/A	N/C
192.	**195.402(a)**	Operator must maintain adequate firefighting equipment at each pump station and breakout tank areas. **.430 (a-c)** **Section 2.6, Map B-3000-16-001**	X			
		The equipment must be:				
193.		a. In proper operating condition at all times. **Section 2.6, Map B-3000-16-001**	X			
194.		b. Plainly marked so that its identity as firefighting equipment is clear. **Section 2.6, Map B-3000-16-001**	X			
195.		c. Located so that it is easily accessible during a fire. **Section 2.6, Map B-3000-16-001**	X			

Comments:

BREAKOUT TANK PROCEDURES		
196.	**195.402(a)**	Utilize PHMSA Form #10 for all Breakout Tank Procedures

SIGN PROCEDURES				S	U	N/A	N/C
197.	**.402(a)**	**.434**	Operator must maintain signs visible to the public around each pumping station and breakout tank area. Section 4.2	X			
198.			Signs must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times. Amdt 195-78 pub. 9/11/03, eff. 10/14/03. Section 4.2	X			

Comments:

		SECURITY of FACILITY PROCEDURES	S	U	N/A	N/C
199.	195.402(a)	Operator must provide protection for each pumping station and breakout tank area and other exposed facilities from vandalism and unauthorized entry. **.436** Section 4.2	X			

Comments:

		SMOKING OR OPEN FLAME PROCEDURES	S	U	N/A	N/C
200.	195.402(a)	Operator must prohibit smoking and open flames in each pump station and breakout tank area where there is the possibility of the presence of hazardous liquids or flammable vapors. **.438** **EOHS 102 3.2**	X			

Comments:

		PUBLIC AWARENESS PROGRAM PROCEDURES **(Also in accordance with API RP 1162)**	S	U	N/A	N/C
1.	192.402(a)	Public Awareness Program in accordance with API RP 1162, (**1st edition Dec-2003**) **.440** **Section 4.**				
2.		The operators program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: **.440(d)**				
3.		(1) Use of a one-call notification system prior to excavation and other	X			
4.		(2) Possible hazards associated with unintended releases from a hazardous liquids or carbon dioxide pipeline facility; Plan does not mention possible hazards associated with release		X		
5.		(3) Physical indications of a possible release; Plan does not mention physical indications associated with release		X		
6.		(4) Steps to be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; Plan does not mention possible hazards associated with release or steps to be taken for public safety		X		
7.		(5) Procedures to report such an event (to the operator).	X			
8.		Does program include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. **.440(e)** Plan does not include such activities		X		
9.		The operator's program and the media used must be comprehensive enough to reach all areas the operator transports gas. **.440(f)** Plan does not include outreach		X		
10.		Is the program conducted in English and any other languages commonly understood by a significant number of the population? **.440(g)** Plan does not mention other languages although given the location, doubtful any language but English would be significant.		X		
11.		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. For operators in existence on June 20, 2005, who must have completed their written programs no later than June 20, 2006, the first evaluation is due no later than **June 20, 2010**. **.440(i)** **New operator.**				X

Comments:

Comments:
The plan as reviewed in Section 4 does not meet the requirements of API RP 1162. AltaGas is questioning how and why they need to comply with this part of the regulation given their location and type of facility. They have 30' of pipeline in the public r/w and everything else is either owned by Conoco Phillips or BP or is behind locked security fencing. However, AltaGas stores HVLs in tanks T1 and T2, 350,000 bbls, 400,000 bbls respectively (currently butane). A major event could be catastrophic. Closest neighbors include Conoco Phillips and Intalco. Closest general public neighbor is at Lake Terrel Rd and Unick, approximately 1 plus mile from facility. Not in an HCA-population or could affect area. Worst case scenarios are detailed in Risk Prevention plan which is regulated by Coast Guard and Clean Air Act. The

DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API 1162)				S	U	N/A	N/C
201.	.402(a)	.442(a)	Is there a written program in place to prevent damage by excavation activities applicable to the operator's pipelines? **Section 4.3 The operator does not have a written damage prevention plan—see notes below.**			X	
202.		.442(b)	Does the operator participate in a qualified One-Call program?	X			
203.		.442(c)(1)	Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. Section 4.3			X	
		.442(c)(2)	Provide for notification to the public in the vicinity of the pipeline and actual notification to the persons identified in paragraph **(c)(1)** of this section of the following, as often as needed to make them aware of the damage prevention program: Section 4.3				
204.			i. The program's existence and purpose.			X	
205.			ii. How to learn the location of underground pipelines before excavation activities are begun.			X	
206.		.442(c)(3)	Provide a means of receiving and recording notification of planned excavation activities. Section 4.3			X	
207.		.442(c)(4)	If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings. Section 4.3			X	
208.		.442(c)(5)	Provide for marking of buried pipelines in the area of excavation activity within **2 business days**. **WAC 480-75-270 RCW 19.122.030** Section 4.3			X	
		.442(c)(6)	Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities: Section 4.3				
209.			i. The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline.			X	
210.			ii. In the case of blasting, any inspection must include leakage surveys.			X	
211.			Does the operator have directional drilling/boring procedures which include taking actions necessary to protect their facilities from the dangers posed by drilling and other trenchless technologies?			X	
			Does the operator review records of accidents and failures due to excavation damage to ensure causes of failures are addressed to minimize the possibility of reoccurrence?			X	
212.			**Damage Prevention (Operator Internal Performance Measures) PHMSA – State Program Evaluation Questions**				
213.			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)			X	
214.			Does operator including performance measures in facility locating services contracts with corresponding and meaningful incentives and penalties?			X	
215.			Do locate contractors address performance problems for persons performing locating services through mechanisms such as re-training, process change, or changes in staffing levels?			X	
216.			Does the operator periodically review the Operator Qualification plan criteria and methods used to qualify personnel to perform locates?			X	
217.			Review operator locating and excavation procedures for compliance with state law and regulations.			X	

DAMAGE PREVENTION PROGRAM PROCEDURES (Also in accordance with API 1162)				S	U	N/A	N/C
218.			Are locates are being made within the timeframes required by state law and regulations? Examine record sample.			X	
219.			Are locating and excavating personnel properly qualified in accordance with the operator's Operator Qualification plan and with federal and state requirements?			X	

DAMAGE PREVENTION PROGAM PROCEDURES (State Requirements)		S	U	N/A	N/C
220.	Terminating the flow of hazardous liquid in pipeline immediately upon receiving information of third party damage. **RCW 19.122.035 (2)** **Section 7.7.1 and 2**	X			
221.	Has the pipeline company visually inspected the damaged pipeline **RCW 19.122.035 (2)** **Section 7.7.1 and 2**	X			
222.	Has the pipeline company determined if the damaged pipeline should be repaired or replaced **RCW 19.122.035 (2)** **Section 7.7.1 and 2**	X			
223.	Notification to local first responders and Dept of Ecology of any reportable release? **Section 7.7.1 and 2.**	X			

Comments:
Altagas believes the exemption under 195.442 (2) below applies to them. They "control" access to their pipeline via guard shack 5 am to 9 pm or cameras with monitoring in control center manned 24/7.
(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.
(2) Pipelines to which access is physically controlled by the operator.

CPM/LEAK DETECTION PROCEDURES			S	U	N/A	N/C
224.	**.402(a)**	Each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of **API 1130, (3rd Edition, September 2007)** in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system. (Amdt 195-94 Pub. 75 FR 48593 8/11/10 eff. 10/01/10). **.134** **AltaGas does not have a CPM detection system**			X	
225.		If a CPM system is installed, operator's procedures for the CPM leak detection system shall comply with **API 1130, (3rd Edition, September 2007)** in operating, maintaining, testing, record keeping, and dispatching training. (Amdt 195-94, 75 FR 48593 Pub. 8/11/10 eff. 10/01/10). **.444; .446(b)(c)** **AltaGas does not have a CPM detection system**			X	

Comments:

CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)			S	U	N/A	N/C
.402(a)	**.446**	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. **AltaGas does not have a control room.**				
	.446(a)	Operator must develop written procedures no later than August 1, 2011, and implement the procedures no later than February 1, 2013. Amdt. 195-93 Pub. 12/03/09 eff. 02/01/10,			X	
	.446(b)	Operator must define roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions including: (1) When making decisions and taking actions during normal operations; (2) When an abnormal operating condition is detected; (3) During an emergency; (4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.			X	

		CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)	S	U	N/A	N/C
	.446(c)(1)	Operator must implement **API RP 1165, (1st Edition, January 2007)** (incorporated by reference, *see* § 195.3) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used.			X	
	.446(c)(2)	Operator must conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays.			X	
	.446(c)(3)	Operator must test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, once each calendar year, NTE 15 months.			X	
	.446(c)(4)	Operator must test any backup SCADA systems once each calendar year, NTE 15 months.			X	
	.446(c)(5)	Operator must implement section 5 of **API RP 1168, (1st Edition, September 2008)** (incorporated by reference, *see* § 195.3) to establish procedures for when a different controller assumes responsibility, including the content of information to be exchanged.			X	
	.446(d)	Operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the defined roles and responsibilities:				
		(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep; (2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue; (3) Train controllers and supervisors to recognize the effects of fatigue; and (4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.			X	
	.446 (e)	If a SCADA system is used, operator must have a written **Alarm Management Plan** including the following provisions to:				
		(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations; (2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities; (3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and once each calendar year, NTE 15 months; (4) Review the alarm management plan required by this paragraph once each calendar year, NTE 15 months, to determine the effectiveness of the plan; (5) Monitor the content and volume of general activity being directed to and required of each controller once each calendar year, NTE 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and (6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.			X	
	.446 (f)	Assure changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:				
		(1) Implement section 7 of API RP 1168 for control room management change and require coordination between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration; and (2) Require field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations.			X	
	.446 (g)	Assure lessons learned from operating experience are incorporated, as appropriate, into control room management procedures by performing each of the following:				
		(1) Review accidents that must be reported pursuant to § 195.50 and 195.52 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to: (i) Controller fatigue; (ii) Field equipment; (iii) The operation of any relief device; (iv) Procedures; (v) SCADA system configuration; and (vi) SCADA system performance. (2) Include lessons learned from the operator's experience in the training program required by this section.			X	

CONTROL ROOM MANAGEMENT PROCEDURES (Amdt. 195-93, 74 FR 63310, December 3, 2009, eff. 2/1/2010)			S	U	N/A	N/C
	.446 (h)	Operator must establish a controller training program to provide for training each controller to carry out the roles and responsibilities defined by the operator and review the training program content to identify potential improvements once each calendar year, NTE 15 months.			X	
	.446(h)	An operator's controller training program must include the following elements:				
		(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence; (2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions; (3) Training controllers on their responsibilities for communication under the operator's emergency response procedures; (4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and (5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.			X	

Required Submission of Data to the National Pipeline Mapping System Under the Pipeline Safety Improvement Act of 2002			S	U	N/A	N/C
	49 U.S.C. 60132, Subsection (b) ADB-08-07	Updates to NMPS: Operators are required to make update submissions every 12 months if any system modifications have occurred. Go to https://www.npms.phmsa.dot.gov/DataReview/login.jsp 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. Section 7.9—AltaGas did change their procedure to be consistent with this rule, however they need to actually update their mapping in the NPMS database to reflect all regulated pipeline including to and from breakout tanks.		X		
	RCW 81.88.080	Pipeline Mapping System: Operator provides 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? AltaGas believes their MOP will be over 250 psi (they are in the process of confirming the MOP see MOP and Pressure Testing sections above); mapping will need to be submitted to the WUTC		X		

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS PROCEDURES			S	U	N/A	N/C
	.452	This form does not cover Liquid Pipeline Integrity Management Programs				

SUBPART G - OPERATOR QUALIFICATION PROCEDURES			S	U	N/A	N/C
	.501 -.509	Refer to Operator Qualification Inspection Forms and Protocols (OPS web page)				

SUBPART H - CORROSION CONTROL PROCEDURES 195.402(a)			S	U	N/A	N/C
226.	**195.402(a)**	Do procedures require that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures for which they are responsible for insuring compliance? **.555 Section 2.3**	X			
		Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is : **.557**				
227.		a) Constructed, relocated, replaced, or otherwise changed after the applicable dates : 3/31/70 - interstate pipelines excluding low stress 7/31/77 -interstate offshore gathering excluding low stress 10/20/85-intrastate pipeline excluding low stress 7/11/91- carbon dioxide pipelines 8/10/94 - low stress pipelines NOTE: This does not include the movement of pipe under **195.424**.	X			
228.		b) Converted under **195.5** and No conversions. 1) Has an external coating that substantially meets **195.559** before the pipeline is placed in service or;			X	
229.		2) Is a segment that is relocated, replaced, or substantially altered? No conversions			X	

SUBPART H - CORROSION CONTROL PROCEDURES 195.402(a)			S	U	N/A	N/C
230.		**Coating Materials;** Section 2.3.1 Coating material for external corrosion control must: a. Be designed to mitigate corrosion of the buried or submerged pipeline; b. Have sufficient adhesion to the metal surface to prevent under film migration of moisture; c. Be sufficiently ductile to resists cracking; d. Have enough strength to resist damage due to handling and soil stress; e. Support any supplemental cathodic protection; and f. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance. **.559**	X			
231.		All external pipe coatings required under **195.557** must be inspected just prior to lowering the pipe in the ditch or submerging the pipe. **.561(a)** Section 2.3.1	X			
232.		All coating damage discovered must be repaired. **.561(b)**	X			
233.		Is cathodic protection applied to pipelines that have been subjected to the conditions listed in **195.557(a) within one (1) year**? **.563(b)** MIP 501	X			
		Each buried or submerged pipeline converted under **195.5** must have cathodic protection if the pipeline- No converted pipelines, no procedures, but acknowledged under Section 2.3.2				
234.		1) Has cathodic protection that substantially meets **195.571** before the pipeline is placed in service, or			X	
235.		2) Is a segment that is relocated, replaced, or substantially altered?			X	
236.		c. All other buried or submerged pipelines that have an effective external coating must have cathodic protection. **MIP 501, 2.2**	X			
237.		d. Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where previous editions of this part required cathodic protection as a result of electrical inspections. **MIP 501, 2.2**	X			
238.		e. Unprotected pipe must have cathodic protection if required by **195.573(b)**.	X			
239.		Test leads installation and maintenance. **.567(b)(c) MIP 501, 2.2**	X			
240.		For placement of test stations at casing? **WAC 480-75-340 MIP 501, 2.2**	X			
241.		Examination of Exposed Portions of Buried Pipelines. **.569** MIP 302	X			
242.		Examination of pipe prior to backfilling. **WAC 480-75-520** MIP 409	X			
243.		Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs **6.2 and 6.3 of NACE Standard RP0169-2007** (incorporated by reference). Amdt 195-94, 75 FR 48593, Pub. 8/11/10 eff. 10/01/10. **.571) Section 2.4**	X			
244.		Pipe to soil monitoring **(annually / 15months)**. **.573(a) Section 2.2**	X			
245.		(1) Separately protected short sections of bare ineffectively coated pipelines **(every 3 years not to exceed 39 months)**. **Do not have short sections or bare pipe**			X	
246.		(2) **Identify not more than 2 years** after cathodic protection is installed, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph **10.1.1.3 of NACE SP 0169-2007.** Amdt 195-94, 75 FR 48593 Pub. 8/11/10 eff. 10/01/10. **MIP 501, 2.2**	X			
		b. Unprotected buried or submerged pipe must be evaluated and cathodically protected in areas in which active corrosion is found as follows; AltaGas does not have any unprotected bare pipe.				
247.		1) Determine areas of active corrosion by electrical survey (closely spaced pipe-to-soil survey), or where electrical survey is impractical, by other means that include review of analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipe environment			X	
248.		2) Before 12/29/2003 - at least **once every 5 years not to exceed 63 months.** Beginning 12/29/2003 - at least **once every 3 years not to exceed 39 months**.			X	
249.		c. Rectifiers, Reverse Current Switches, Diodes, Interference Bonds whose failure would jeopardize structural protection - **at least 6 times each year, intervals not to exceed 2-1/2mos.**				

SUBPART H - CORROSION CONTROL PROCEDURES 195.402(a)			S	U	N/A	N/C
250.		d. Inspect each cathodic protection system used to control corrosion on the bottom of an aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. (Not required if it is noted in the corrosion control procedures why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.)			X	
251.		e. Any deficiencies identified in corrosion control must be corrected as required by **195.401(b)**. Section 2.3	X			
252.		Remediation of corrosion system deficiencies initiated within 90 days of discovery **WAC 480-75-510** Section 2.3	X			
253.		Are there adequate provisions for electrical isolations? **.575** **MIP 501**	X			
254.		a. For pipelines exposed to stray currents, is there a program to minimize the detrimental effects. **MIP 501** b. Design & install CP systems to minimize effects on adjacent metallic structures. **.577**	X			
255.		a. For pipelines that transport any hazardous liquid or carbon dioxide that would corrode the pipe, are corrosive effects investigated and adequate steps taken. Section 2.3 MIP 502	X			
256.		b. Internal Corrosion - Inhibitors - do procedures show that they are to be used in conjunction with coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion. **.579** Section 2.3 MIP 502	X			
257.		Coupons or other monitoring equipment must be examined **at least 2 times each year, not to exceed 7-1/2 months.** Section 2.3 MIP 502	X			
258.		c. Whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion as well as the adjacent pipe. Section 2.3 MIP 502	X			
259.		Are pipelines protected against Atmospheric Corrosion using required coating material? (See exception to this statement). **.581(a)** Section 2.3 MIP 501	X			
		Atmospheric corrosion monitoring - **.583** **ONSHORE** - At least **once every 3 years but at intervals not exceeding 39 months.** **OFFSHORE** - At least **once each year, but at intervals not exceeding 15 months**.				
260.		**(b)** Inspect pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. Section 2.3.4.	X			
261.		**(c)** If atmospheric corrosion is found during an inspection, procedures for protection against the corrosion as per §195.581.	X			
262.		Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace pipe if general corrosion has reduced the wall thickness? **.585(a)** **MIP 403 5.1.4**	X			
263.		Are procedures in place and are they followed to either reduce the **MOP**, or repair/replace if localized corrosion has reduced the wall thickness? **.585(b)** **MIP 403 5.1.4**	X			
264.		Are applicable methods used in determining the strength of corroded pipe **(ASME B-31G, RSTRENG)?** **.587** **MIP 403, 5.1**	X			
265.		Corrosion Control Records Retention (Some are required for **5 yrs)** (Note - §§195.569, 195.573(a & b), and 195.579(b)(3) & (c) for the life of the pipeline). **.589** Section 2.3.3	X			

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

Comments:

Recent PHMSA Advisory Bulletins (Last 2 years)

Leave this list with the operator.

Number	**Date**	**Subject**
ADB-2013-07	July 12, 13	Potential for Damage to Pipeline Facilities Caused by Flooding
ADB-12-10	Dec 5, 12	Using Meaningful Metrics in Conducting Integrity Management Program Evaluations
ADB-12-09	Oct 11, 12	Communication During Emergency Situations
ADB-12-08	Jul 31, 12	Inspection and Protection of Pipeline Facilities After Railway Accidents
ADB -12-06	May 7, 12	Verification of Records Establishing MAOP and MOP.
ADB-12-04	Mar 21, 12	Implementation of the National Registry of Pipeline and Liquefied Natural Gas Operators
ADB -12-03	Mar 6, 12	Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation

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