GAS STORAGE FIELD REVIEW

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

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	Al Jones / July 13, 2009	**Sr Eng Review Date:**	David Lykken / July 14, 2009
		Peer Review/Date:	Tom Finch
		Director Approval/Date:	Chris Hoidal

POST INSPECTION MEMORANDUM (PIM)			
Name of Operator:	Puget Sound Energy	**OPID #:**	22189
Name of Unit(s):	Jackson Prairie Storage Facility	**Unit #(s):**	3387
Records Location:	Jackson Prairie Storage Facility		
Unit Type & Commodity:	Interstate Natural Gas Storage		
Inspection Type:	Standard	**Inspection Date(s):**	June 8-11, 2009
PHMSA Representative(s):	Al Jones, WUTC	**AFO Days:**	4

Summary:
No probable noncompliance were identified and five Areas of Concerns are addressed with recommendations for future evaluation listed the Findings, below.

Record Review:
Included cathodic protection for plant piping and transmission pipeline including casings and rectifiers, maintenance of valves, pressure recording charts, Emergency Plan, Saftey related condition reports, and Welding results,

Field Inspection:
Included new wellhead consturction, new trubine/conpressor station, CP for piping and rectifier units, ROW, firefighting equipemnt, pipe supports, and facility security systems.

Future Inspection:
It was recommended that future inspections be scheduled in the Fall of the year as in previous years.

Findings:
Area of Concerns:

1. The compressor stations are equipped with automatic exhaust ventilation systems that are activated by temperature setting within each building. The exhaust fans will not activated if gas accumulates in the buildings. The gas detectors are designed to ESD the station at 40% LEL. While testing of the gas sensors, the station's ESD was activated, detected in the control room, and the ventilation blowers were not activated to exhaust the gas. The ventilation system is currently wired to operate to vent heat at a predetermined temperature setting, not for the ventilation of gas. CFR 192.173 Compressor Stations: Ventilation, address employees safety where gas could accumulate in a room. Staff recommends that all compressor buildings be wired to automatically activate the exhaust ventilation systems when gas is detected in the building at least 40% LEL.

2. Several above ground pipe supports were found with atmospheric corrosion between the support and the bottom of the pipe. Insulating saddles have been installed at similar location except at: wells #88, well #89, and SU #10 (Zone 1 storage piping).

3. The Gas Field Procedure Manual list several reasons for Abnormal Operating Conditions (Section 4515.1205) when a positive pipe-to-soil reading is observed while using a copper-copper sulfate cell. The list is not comprehensive and omits lessons learned from another PSE's rectifier problem. It is recommended that the manual include the possibility that a rectifier could be incorrectly wired to the pipeline and the anode. Jackson Prairie Storage rectifiers (49 units???) operate at 440 vAC, safety precautions need to be reviewed with the operator, and verify rectifier output wires to the pipe and anode are properly identified.

4. The Gas Operation Standards revised section (effective 3/1/2009) for compliance with CFR 192.615 (b)(3) Emergency Plans - review employee activities to determine whether the procedures were effectively followed in each emergency. The Standards Manual require periodic refresher training such as table top or simulation exercises be provided and verify the effectiveness of the

GAS STORAGE FIELD REVIEW

Findings:

training. Staff recommends such exercises be documented for attendance; identify the emergency skills reviewed, the effectiveness of the training i.e. what worked and what needs to be improved.

5. The only exception to the minimum CP threshold was at the Triethylene Glycol (TEG) piping located near the concrete footings within the plant facility. The TEG lines are not considered jurisdictional piping, but could impact the plant's operation if the line were to fail from a corrosion leak. Staff recommend the low pipe-to-soil values (-0.576 vDC and -0.76 vDC) found on a 2" diameter pipe near coalescer tower #10, be mitigated by placing anodes in proximity to the pipelines.

Name of Operator:	Puget Sound Energy - Jackson Prairie Storage Facility		
OP ID No. [1] **22189**		**Unit ID No.** [1] **33875**	
HQ Address:		**System/Unit Name & Address:** [1]	
Puget Sound Energy PO Box 90868, EST-07W Bellevue, WA 98009-0868		Jackson Prairie Storage Facility 239 Zandecki Road Chehalis, WA 98532	
Co. Official:	Burt A.Valdman, Executive VP & COO	**Activity Record ID No.:**	PG-090328
Phone No.:	425-462-3193	**Phone No.:**	360-262-3365
Fax No.:		**Fax No.:**	360-262-0119
Emergency Phone No.:	800-552-7171	**Emergency Phone No.:**	360-262-3365

Persons Interviewed	Title	Phone No.
Jim Janson	Manager, Jackson Prairie Storage Operations	360-262-3365
Rick Braaten	Supervisor	360-262-3365
Darryl Hong	Compliance Coordinator	425-462-3911

PHMSA Representative(s) [1] **Al Jones/UTC** **Inspection Date(s)** [1] **June 8-11, 2009**

Company System Maps (Copies for Region Files):

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

GAS STORAGE FIELD REVIEW

Counties of Operation: (list each field separately)
Jackson Prairie Natural Gas Storage Facility is located in Lewis County, Washington, about 10 miles south of Chehalis, or about 100 miles south of Seattle.

Storage Field(s) Description: (list each field separately)
Jackson Prairie storage is the 14th largest storage reservoir in the United States in terms of capacity for natural gas withdrawal and delivery to consumers. The facility is co-owned with equal rights with Puget Sound Energy, Avista Utilities, and Williams Northwest Pipeline. The facility was authorized for underground storage of natural gas in 1963 and certified for commercial service in 1970. Today, the facility has storage for 23 billion cubic feet and is expanding capacity to 25 billion cubic feet by 2012 with an additional 48 billion cubic of "cushion" to provide pressure in the reservoirs. The facility consists of a series of deep, underground reservoirs of porous sandstone deposits approximately 1,000 to 3,000 feet below the ground surface. The storage facility has 102 wells spread across 3,200 acres for injection and withdrawal points for natural gas. The facility can meet up to 25% of the Pacific Northwest's peak natural gas demand on the coldest winter days. Major components of the facility includes: four transmission pipeline, well points, gathering lines, filtration, coalesce, dehydration, compression units for injection to the storage field or interstate pipeline, and SCADA control unit.

Inspection Summary:
Expansion:
Since the last inspection in August 2007, the Storage capacity has expanded its working storage by approximately 28%, constructed ten new injection wells, replaced three 1966 vintage Saturn turbines with three new 1,600Hp Saturn T20 units, and commissioned the 10,500HP Taurus turbine/compressor unit.

Slug Catcher:
Internal corrosion and design of the slug catcher has been identified in previous inspections. The long term plan is to replace the slug catcher with an above ground unit. I was informed the unit will not be replace within the next five years because of budget issues. The slug catcher was placed into service in 1999 with schd 40 X52 pipe, 0.750" wt.. A corrosion coupon was installed near the bottom of the unit on December 8, 2003. The coupon material (per vendor, Rhorback) is made from mild steel (1018) with chemical properties similar to any carbon steel. The average corrosion rate of seventeen coupons is approximately 2.77 mills per year (mpy) excluding the corrosion rate between September 22 and December 8, 2008 where the rate was 15.01 mpy. It is difficult to correlate the rate of corrosion between coupons and the slug catcher. The coupons verify corrosion is present at the slug catcher and one coupon indicated pitting. The slug catcher is located near the main entrance and the control room to the plant and needs to be given a high priority for employee safety. With the expansion of the storage facility the rate of corrosion at the slug catcher should increase.

Cathodic Protection Review:
Numerous pipe-to-soil potentials were taken (see field data report) and were found to be in compliance. The only exception to the minimum CP was at the Triethylene Glycol (TEG) piping located near the concrete footings within the plant facility. The TEG lines are not considered jurisdictional piping, but could impact the plant's operation if the line were to fail from a corrosion leak.

The attached evaluation form should be used in conjunction with 49CFR Parts 191 and 192.

PIPE TYPE						
	Bare steel	**Coated steel**	**Ineffectively Coated**	**Pre70-ERW**	**Plastic**	**Other: must specify type**
Footage/Mileage		**14.4 Miles**				

PIPE SPECIFICATIONS (2" AND LARGER)						
Diameter(s)	**14-inch**	**16-inch**	**20-inch**	**24-inch**		
Pipe Grade(s)	**X-46**	**X-52**	**X-56**	**X-70**		
Wall Thickness(s)	**0.250 inch**	**0.312 inch**	**0.375 inch**	**0.250-0.365 inch**		
Footage/Mileage	**9,031 Ft**	**9,029 Ft**	**9,053 Ft**	**9,014 Ft**		

GAS STORAGE FIELD REVIEW

WELL STIMULATION

ACIDIZING

Acidizing treatments used to stimulate the wells?	☒ Yes ☐ No
Type(s) of acids used in treating the wells:	15% HCl
Type(s) of inhibitors used with the acid(s):	Varies
Frequency of the treatments: Rare. Last used in late 1990's	Volume of acid per treatment: <600 Gal.
Well cleanup procedure following treatment:	Yes, flowed back into the well procedure.
If treatment is flowed back into the well/injection line, criteria used to determine that the treatment will not cause internal corrosion or erosion of the pipe:	Nothing specific

FRACTURING

Fracturing treatments used to stimulate the wells?	☐ Yes ☒ No
Type(s) of fracturing fluids used in treating the wells:	N/A
Type(s) of inhibitors used with the fracturing fluid(s):	N/A
Frequency of the treatments: N/A	Amount of sand per treatment: N/A
Well cleanup procedure following treatment:	N/A
If treatment is flowed back into the well/injection line, criteria used to determine that the treatment will not cause internal corrosion or erosion of the pipe:	N/A

GAS STORAGE FIELD REVIEW

GAS and LIQUID HANDLING FACILITIES

GAS COMPRESSION

Location of compressors:	Jackson Prarie Compressor Station
Number, Size (HP), and Date of Installation of Units:	C-1 670Hp 10/65 Walkinshaw reciprocating engine used at Zone 9 for reinjection of gas. C-2 1,000Hp 11/66 Saturn turbine/compressor. In 2008 was replaced with 1,600Hp Saturn T20 C-3 1,000Hp 9/66 Saturn turbine/compressor. In 2008 was replaced with 1,600Hp Saturn T20 C-4 1,000Hp 11/66 Saturn turbine/compressor. In 2008 was replaced with 1,600Hp Saturn T20 C-5 1,300Hp 12/68 Saturn turbine/compressor C-6 4,417Hp 11/73 Centaur turbine/compressor C-7 4,417Hp 11/75 Centaur turbine/compressor C-8 7,000Hp 11/99 Taurus-60 turbine/compressor C-9 10,500Hp 11/08 Taurus-70 turbine/compressor IR-1 145Hp 1/01 Caterpillar engine for recycle gas within the storage field. IR-2 145Hp 1/02 Caterpillar engine for recycle gas within the storage field. IR-3 75Hp 3/09 Electric compressor for recycle gas within the storage facility

GAS DEHYDRATION

Location of dehydration units:	Jackson Prarie Compressor Station		
Type(s) of dehydration process used:	Glyco, bubble cap tray, triethylene glycol at 1,150 MMCF/Day.		
Number of dehydration units:	12 towers	Dehydration capacity:	One Billion Cubic Feet per Day

GAS SWEETENING (Acid Gas Treating)

Location of sweetening units:	N/A		
Type(s) of sweetening process used:	N/A		
Number of sweetening units:	N/A	Sweetening capacity:	N/A

GAS / LIQUID SEPARATION

SCRUBBERS / SEPARATORS:	Yes		
Location of scrubbers/separators:	At each gas well site has a two-phase separator and at the plant facility there three vortex separators for water removal.		
Type(s) of scrubbers/separators used:	Two-Phase separators		
Number of scrubbers/separators:	54	Separation capacity:	20 to 80 Million CF/Day
DRIPS:	Yes		
Location of drips:	Station and at low elevations along the pipeline		
Type(s) of drips used:	Slug-Catcher at the Plant Station		
Number of drips:	One at the Plant Station and three field sites.		
Frequency of draining or blowing drips:	As needed		

GAS STORAGE FIELD REVIEW

FIELD OPERATING PARAMETERS

PRESSURES, RATES and TEMPERATURES

	Pressure, psi		Flow Rate, MMcf/day		Temperature, °F	
	Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal
Maximum	855	800	450	1,150	110	110
Maximum	370	370	50	50	40	40

Maximum Allowable Operating Pressure (Field): 800 psig

WATER, CO_2, and O_2 CONTENT

	Water, lbs./MMcf	CO_2,	H_2S, ppm	O_2, %
Injection Cycle	7 #	0.04%	0	Negligible
Withdrawal Cycle	28 to 30 #	0.04%	0	Negligible

FIELD OPERATING AND MAINTENANCE HISTORY

LEAKS (NON-RUPTURES)

Are leak surveys of the field being conducted? (49 CFR 192.706) ☒ Yes ☐ No

Have any leaks been found over the past 5 years? ☐ Yes ☒ No | Number of leaks: 0

Types of leaks that have occurred?
N/A

Cause(s) of the leaks:
N/A

Location(s) of the leaks:
N/A

Has a trend analysis been performed? ☐ Yes ☐ No

If a trend analysis has been done, what do the results indicate?

FAILURE/RUPTURES

Have any failures occurred over the past 5 years? ☐ Yes ☒ No | Number of failures: 0

Type(s) of failures that have occurred:

Cause(s) of the failures:

Location(s) of the failures:

Has a trend analysis been performed? ☐ Yes ☐ No

If a trend analysis has been done, what do the results indicate?

LINE REPLACEMENTS

Have any lines been replaced over the past 5 years? ☒ Yes ☐ No | Number of replacements: 1

Type(s) of replacements:
14" Diameter Tee

Location(s) of the replacements:
Approximately 500 yds. west of compressor Station

Reason(s) for replacements:
To make Certification Data Current.

LINE REPAIRS

GAS STORAGE FIELD REVIEW

FIELD OPERATING AND MAINTENANCE HISTORY

Have any lines been repaired over the past 5 years?	☒ Yes	☐ No	Number of repairs: 1

Type(s) of repairs:
14" diameter Tee Replacement

Location(s) of the repairs:
Approximately, 500 yds west of Compressor Station

Reason(s) for the repairs:
To make Certification Data Current.

VALVE REPLACEMENTS

Have any valves been replaced over the past 5 years?	☒ Yes	☐ No	Number of replacements: 1

Type(s) of valve replacements:
14" diameter Valve at Meter Station & Williams Tap.

Location(s) of the replacements:
Williams Tap

Reason(s) for the replacements:
For Pressure Protection with actuator set at MAOP.

GAS and LIQUID HANDLING FACILITY UPSETS

	Gas Dehydration Units	Gas Sweetening Units	Separators
Number of upsets – past 3 years	None	N/A	None

Cause(s) of the upsets:

Has a trend analysis been performed? ☐ Yes ☐ No

If a trend analysis has been done, what do the results indicate?

CORROSION CONTROL AND MONITORING

EXTERNAL CORROSION

Are the field piping and related storage field facilities cathodically protected? (49 CFR 192 Subpart I) ☒ Yes ☐ No

Type(s) of cathodic protection used: ☒ Impressed Current ☐ Galvanic Anodes ☐ Combination

Criteria used to determine adequate cathodic protection:
-850 mVdc, ON

Does the field piping system contain any bare or ineffectively coated pipe? ☐ Yes ☒ No

Location(s) of the bare or ineffectively coated pipe:
N/A

Amount of bare of ineffectively coated pipe:
N/A

Are corrosion monitoring procedures established for the field piping and related storage field facilities? ☒ Yes ☐ No

MONITORING

Pipe-to-soil readings	☒ Yes	☐ No	Exposed pipe reports	☒ Yes	☐ No
Close interval surveys	☐ Yes	☒ No	Leak surveys	☒ Yes	☐ No
Line current surveys	☐ Yes	☒ No	Instrumented inspection surveys	☐ Yes	☒ No

Remedial measures taken to mitigate corrosion:

A corrosion coupon was installed near the bottom of the slug catcher unit.

GAS STORAGE FIELD REVIEW

INTERNAL CORROSION

Are corrosion monitoring procedures established for the field piping and related storage field facilities? ☒ Yes ☐ No

MONITORING

Corrosion coupons	☒ Yes	☐ No	Pipe replacement reports surveys	☒ Yes	☐ No
Gas samples	☐ Yes	☒ No	Leak surveys	☐ Yes	☒ No
Water samples	☐ Yes	☒ No	Instrumental inspection surveys	☐ Yes	☒ No
Solids samples	☐ Yes	☒ No			

CORROSION COUPONS

Frequency coupons are analyzed:
Quarterly

Location(s) where coupons are installed:
At Slug-Catcher.

GAS SAMPLES

Frequency of sampling: Random

Location(s) where the samples taken:
At Wellheads.

Are the gas samples analyzed for:

Carbon dioxide	(CO_2)	☒ Yes	☐ No
Hydrogen sulfide	(H_2S)	☒ Yes	☐ No
Oxygen	(O_2)	☒ Yes	☐ No
Water vapor		☒ Yes	☐ No

Amount of the following present in the gas:

Carbon dioxide (CO_2)	Not detected in February 2006.
Hydrogen sulfide (H_2S)	Not detected
Oxygen (O_2)	Not detected
Water vapor	Varies. Water is collected at low points near wellhead and drained from pipeline.

What carbon dioxide (CO_2) partial pressure criteria are used to establish carbon dioxide (CO_2) corrosivity ranges?
N/A

What is the carbon dioxide (CO_2) corrosivity ranges?
N/A

What is the carbon dioxide (CO_2) partial pressure? Insignificant

WATER/LIQUIDS SAMPLES

Frequency of sampling: As needed

Locations where the samples are taken:
At well heads.

What constituents are the water samples analyzed for? **(Refer to the Water Analysis Checklist)**
Last tested in January 1985

Concentration of the following present in water:

Iron	(Fe^{++})	1.0 ppm
Manganese	(Mn^{++})	0.18 ppm
Chlorides	(Cl^-)	19,000 ppm
Sulfates	($SO_4^{=}$)	2 ppm

Amount of the following gases dissolved in the water:

Carbon dioxide	(CO_2)	Varies 0.06 - 0.47 ppm
Hydrogen sulfide	(H_sS)	0
Oxygen	(O_2)	Not tested

Is the pH of the water below 6.8? ☒ Yes ☐ No

Is hydrostatic test water sampled for the presence of bacteria? ☐ Yes ☒ No

GAS STORAGE FIELD REVIEW

INTERNAL CORROSION		
Are liquids tested for evidence of excessive glycol in the pipeline, which if deteriorated, could lower the pH?	☐ Yes	☒ No

SOLIDS SAMPLES (collected at pig receivers)

Frequency of sampling: N/A. No pigging has been preformed.

Locations where the samples taken:

Are solids observed and/or tested for the following components?

Iron Oxide	☐ Yes	☐ No	Scales	☐ Yes	☐ No
Iron Sulfide	☐ Yes	☐ No	Sand	☐ Yes	☐ No

Is the volume of solids increasing or decreasing between pig runs?

Comments:

INSTRUMENTED INSPECTION SURVEYS

Frequency surveys are conducted: N/A

Lines that have been surveyed and when the survey was conducted:

INHIBITOR PROGRAM

Has a corrosion inhibitor program been established for the field piping and related storage field facilities?	☐ Yes	☒ No

When did the program start?

Type(s) of treatment method used: ☐ Batch ☐ Continuous

Type(s) of inhibitors used:

Are liquid samples periodically taken to test for residual corrosion inhibitor, to help determine effectiveness?	☐ Yes	☐ No

MAINTENANCE PIGGING

(See also solids and water sampling, inhibitor sections)

Does operator have a maintenance pigging program designed to sweep the lines of sediments and/or scale?	☐ Yes	☒ No
Does operator adhere to the pigging program?	☐ Yes	☐ No

Comments:

GAS STORAGE FIELD REVIEW

CONTROLLING GAS VELOCITY – INTERNAL CORROSION AND EROSION
Have target flow rates been determined for the field piping system? ☐ Yes ☒ No
Are injection/withdrawal flow rates kept within the targeted flow rates, to minimize sediment and water build-up, and to manage erosion? ☐ Yes ☒ No
Has erosion been observed during replacement of components (lines, valves, fittings, etc.)? ☐ Yes ☒ No
Locations where erosion has been found:
Remedial measures taken to mitigate erosion:

ATMOSPHERIC CORROSION
Are corrosion monitoring procedures established for the field piping and related storage field facilities? ☒ Yes ☐ No
Location(s) where corrosion has been found: Various Locations
Remedial measures taken to mitigate corrosion: Yes, replaced pipe rapping at soil/air interface and atmospheric corrosion where painting is required.

SAFETY DEVICES and SYSTEMS

SURFACE FACILITIES	
Has a system safety analysis of the field piping and related storage facilities been performed: ☒ Yes ☐ No	
Has a safety analysis function evaluation chart for the field piping and related storage field facilities been prepared? ☒ Yes ☐ No	
PRESSURE SAFETY DEVICES:	
COMPRESSORS	
Is each compressor, per 49 CFR 192.169, equipped with pressure safety devices for overpressure protection? ☒ Yes ☐ No	
Pressure protection provided by:	Location of pressure safety devices:
Primary **Compressor Controls**	Primary At Skid
Secondary **Station Controls (Solfwear)**	Secondary At SCADA Station
PRESSURE VESSELS	
Is the working pressure of each pressure vessel (dehydrator, scrubber, etc.) greater than the MAOP? ☒ Yes ☐ No	
Is each pressure vessel equipped with pressure safety devices for overpressure protection? ☒ Yes ☐ No	
Pressure protection provided by:	Location of pressure safety devices:
Primary **Station Over Pressure Protection via ESD or SSD.**	Primary **Station Blow Down Tower.**
Secondary **Relief valves at vessels**	Secondary **At four cooler stations.**
HEADERS, LATERALS and WELL LINES	
Are the headers, laterals and well lines equipped with pressure safety devices for overpressure protection? ☒ Yes ☐ No	
Pressure protection provided by:	Location of pressure safety devices:

GAS STORAGE FIELD REVIEW

SURFACE FACILITIES			
Primary	Station Over Pressure via ESD or SSD.	Primary	At Conpressor Station Facility
Secondary	Station Over Pressure via ESD or SSD.	Secondary	At Conpressor Station Facility

GAS DETECTION SAFETY DEVICES:

Is each compressor, per 49 CFR 192.736, building equipped with gas detection safety devices?	☒ Yes	☐ No
Are other buildings that contain gas handling equipment equipped with gas detection safety devices?	☒ Yes	☐ No

Type(s) of gas detection safety devices: ☒ Combustible gas (L.E.L.) ☐ Hydrogen Sulfide (H_2S) ☐ Other:

Type(s) of alarms used to notify personnel to the presence of gas: ☐ Visual ☐ Audible ☒ Combination

FIRE DETECTION SAFETY DEVICES:

Is each compressor building equipped with fire detection safety devices?	☒ Yes	☐ No
Are other buildings that contain gas handling equipment equipped with fire detection safety devices:	☒ Yes	☐ No

Type(s) of fire detection safety devices:
☒ Flame ☐ Heat ☐ Smoke ☐ Fusible Material
☐ Other: UV & IR

Type(s) of alarms used to notify personnel to the presence of fire:
☐ Visual ☐ Audible ☒ Combination

EMERGENCY SHUTDOWN SYSTEM:

Is each compressor station, per 49 CFR 192.167, equipped with a remote controlled emergency shutdown system?	☒ Yes	☐ No
Does the gas detection system activate the compressor station emergency shutdown system?	☒ Yes	☐ No
Does the fire detection system activate the compressor station emergency shutdown system?	☒ Yes	☐ No

WELLS

Is each well equipped with a well storage safety valve?	☒ Yes	☐ No
If not, are there plans to equip each well with a well storage safety valve?	☐ Yes	☐ No

Reasons why wells should not be equipped with well storage safety valve(s)?

ADDITIONAL COMMENTS
Compressor stations are set to ESD at 40% LEL.

WATER ANALYSIS CHECKLISTS

Constituent		Does Operator test for . . . Yes	No	Operator's "threshold"	Constituent		Does Operator test for . . . Yes	No	Operator's "threshold"
Sodium	Na^+	☒	☐		Chloride	Cl^-	☒	☐	
Potassium	K^+	☒	☐		Sulfate	$SO_4^=$	☒	☐	
Calcium	Ca^{++}	☒	☐		Carbonate	$CO_3^=$	☒	☐	
Magnesium	Mg^{++}	☒	☐		Bicarbonate	HCO_3^-	☒	☐	
Iron	Fe^{++}	☒	☐		Hydroxide	OH^-	☐	☒	
Barium	Ba^{++}	☐	☒		Dissolved Oxygen	O_2	☒	☐	
Strontium	Sr^{++}	☐	☒		Dissolved Carbon Dioxide	CO_2	☐	☒	
Manganese	Mn^{++}	☒	☐		Dissolved Hydrogen Sulfide	H_2S	☐	☒	
Lead	Pb	☒	☐				☐	☐	
Zinc	Zn	☒	☐				☐	☐	

Other	Does Operator test for . . . Yes	No	Operator's "threshold"	Other	Does Operator test for . . . Yes	No	Operator's "threshold"
Acidity	☒	☐		Alkalinity	☒	☐	
pH	☒	☐		Salinity	☒	☐	19,000 ppm
Total Dissolved Solids (TDS)	☒	☐	34,000 ppm	Acid-producing Bacteria	☐	☒	
Sulfate-reducing Bacteria	☐	☒					

Excessive values of the above-listed constituents and properties, dependent upon operating conditions and other factors that may be unique to the storage field, could indicate a corrosive condition in the pipeline.

GAS STORAGE FIELD REVIEW

Unless otherwise noted, all code references are to 49CFR Part 192. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

PIPELINE INSPECTION (Field)		S	U	N/A	N/C
.143/(b)/.476	Design and construction of new and replaced transmission line and components.	X			
.179	Valve Protection from Tampering or Damage	X			
.463	Cathodic Protection	X			
.465	Rectifiers	X			
.479	Pipeline Components Exposed to the Atmosphere	X			
.605	Knowledge of Operating Personnel	X			
.707	ROW Markers, Road and Railroad Crossings	X			
.719	Pre-pressure Tested Pipe (**Markings and Inventory**)	X			
.739/.743	Pressure Limiting and Regulating Devices (spot-check field installed equipment vs. inspection records)			X	
.745	Valve Maintenance	X			
.751	Warning Signs	X			
.801 - .809	Operator Qualification - Use PHMSA Form 15 Operator Qualification Field Inspection Protocol Form	X			

Comments:
Pressure regulators and limiting devices are for the Intermediate Distribution System that is covered in PSE's Lewis County Inspection.

COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")		S	U	N/A	N/C
.143/(b)/.476	Design and construction of new and replaced transmission line and components (excludes offshore or facilities installed or replaced before 05/23/07).	X			
.163 (c)	Main operating floor must have (at least) two (2) separate and unobstructed exits	X			
	Door latch must open from inside without a key	X			
	Doors must swing outward	X			
(d)	Each fence around a compressor station must have (at least) 2 gates or other facilities for emergency exit	X			
	Each gate located within 200 ft of any compressor plant building must open outward	X			
	When occupied, the door must be opened from the inside without a key	X			
(e)	Does the equipment and wiring within compressor stations conform to the **National Electric Code, ANSI/NFPA 70?**	X			
.165(a)	If applicable, are there liquid separator(s) on the intake to the compressors?	X			
.165(b)	Do the liquid separators have a manual means of removing liquids?	X			
	If slugs of liquid could be carried into the compressors, are there automatic dumps on the separators, Automatic compressor shutdown devices, or high liquid level alarms?	X			
.167(a)	ESD system must:				
	- Discharge blowdown gas to a safe location	X			
	- Block and blowdown the gas in the station	X			
	- Shut down gas compressing equipment, gas fires, electrical facilities in compressor building and near gas headers	X			
	- Maintain necessary electrical circuits for emergency lighting and circuits needed to protect equipment from damage	X			
	ESD system must be operable from at least two locations, each of which is:				
	- Outside the gas area of the station	X			
	- Not more than 500 feet from the limits of the station	X			
	- ESD switches near emergency exits?	X			

GAS STORAGE FIELD REVIEW

Unless otherwise noted, all code references are to 49CFR Part 192. S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
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COMPRESSOR STATIONS INSPECTION (Field) (Note: Facilities may be "Grandfathered")		S	U	N/A	N/C
.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?			N/A	
.171(a)	Does the compressor station have adequate fire protection facilities? If fire pumps are used, they must not be affected by the ESD system.			X	
(b)	Do the compressor station prime movers (other than electrical movers) have over-speed shutdown?	X			
(c)	Do the compressor units alarm or shutdown in the event of inadequate cooling or lubrication of the unit(s)?	X			
(d)	Are the gas compressor units equipped to automatically stop fuel flow and vent the engine if the engine is stopped for any reason?	X			
(e)	Are the mufflers equipped with vents to vent any trapped gas?	X			
.173	Is each compressor station building adequately ventilated?	X			
.457	Is all buried piping cathodically protected?	X			
.481	Atmospheric corrosion of aboveground facilities	X			
.603	Does the operator have procedures for the start-up and shut-down of the station and/or compressor units?	X			
	Are facility maps current/up-to-date?	X			
.615	Emergency Plan for the station on site?	X			
.619	Review pressure recording charts and/or SCADA	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:
Intermediate distribution pressure gas is covered in PSE's Lewis County Inspection.

REPORTING PERFORMANCE AND RECORDS		S	U	N/A	N/C
191.5	Telephonic reports to NRC (800-424-8802)			X	
191.15	Written incident reports; supplemental incident reports (DOT Form PHMSA F 7100.2)			X	
191.17 (a)	Annual Report (DOT Form PHMSA F 7100.2-1)	X			
191.23	Safety related condition reports			X	
192.727 (g)	Abandoned facilities, onshore crossing commercially navigable waterways reports			X	

CONSTRUCTION PERFORMANCE AND RECORDS		S	U	N/A	N/C
.225	Test Results to Qualify Welding Procedures	X			
.227	Welder Qualification	X			
.241 (a)	Visual Weld Inspector Training/Experience	X			
.243 (b)(2)	Nondestructive Technician Qualification	X			
(c)	NDT procedures	X			
(f)	Total Number of Girth Welds	X			
(f)	Number of Welds Inspected by NDT	X			

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	CONSTRUCTION PERFORMANCE AND RECORDS	S	U	N/A	N/C
(f)	Number of Welds Rejected	X			
(f)	Disposition of each Weld Rejected	X			
.303	Construction Specifications	X			
.325	Underground Clearance	X			
.327	Amount, Location, Cover of each Size of Pipe Installed	X			
.455	Cathodic Protection	X			

		OPERATIONS and MAINTENANCE PERFORMANCE AND RECORDS	S	U	N/A	N/C
.603(b)	.605(a)	Procedural Manual Review – Operations and Maintenance (**1 per yr/15 months**)	X			
.603(b)	.605(c)	Abnormal Operations	X			
.603(b)	.605(b)(3)	Availability of construction records, maps, operating history to operating personnel	X			
.603(b)	.605(b)(8)	Periodic review of personnel work – effectiveness of normal O&M procedures	X			
.603(b)	.605(c)(4)	Periodic review of personnel work – effectiveness of abnormal operation procedures	X			
.709	.614	Damage Prevention (**Miscellaneous**)	X			
.709	.609	Class Location Study (**If Applicable**)	X			
.603(b)	.615(b)(1)	Location Specific Emergency Plan	X			
.603(b)	.615(b)(2)	Emergency Procedure training, verify effectiveness of training	X			
.603(b)	.615(b)(3)	Employee Emergency activity review, determine if procedures were followed.	X			
.603(b)	.615(c)	Liaison Program with Public Officials	X			
.605(a)	.616	Public Awareness Program also in accordance with API RP 1162				
	.616(e & f)	Documentation properly and adequately reflects implementation of operator's Public Awareness Program requirements - Stakeholder Audience identification, message type and content, delivery method and frequency, supplemental enhancements, program evaluations, etc. (i.e. contact or mailing rosters, postage receipts, return receipts, audience contact documentation, etc. for emergency responder, public officials, school superintendents, program evaluations, etc.). See table below:	X			

X	
X	**Baseline Message Frequency (starting from effective date of Plane)**
X	2 years
X	Annual
X	3 years
X	Annual
X	As required of One-Call Center
X	**Baseline Message Frequency starting from effective date of Plane)**
X	Annual
X	Annual
X	3 years
X	Annual
X	As required of One-Call Center

			S	U	N/A	N/C
	.616(g)	The program must be conducted in English and any other languages commonly understood by a significant number of the population in the operator's area?	X			
.517		Pressure Testing	X			
.709	.619	Maximum Allowable Operating Pressure (**MAOP**)	X			
.709	.625	Odorization of Gas			X	
.709	.705	Patrolling (**Refer to Table Below**)	X			

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

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

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

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

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

			S	U	N/A	N/C
.603b/.727g	.727	Abandoned Pipelines also Underwater Facility Reports if applicable			X	
.709	.731(a)	Compressor Station Relief Devices (**1 per yr/15 months**)	X			
.709	.731(c)	Compressor Station Emergency Shutdown (**1 per yr/15 months**)	X			
.709	.736(c)	Compressor Stations – Detection and Alarms (**Performance Test**)	X			
.709	.739	Pressure Limiting and Regulating Stations (**1 per yr/15 months**)			X	
.709	.743	Pressure Limiting and Regulator Stations – Capacity (**1 per yr/15 months**)			X	
.709	.745	Valve Maintenance (**1 per yr/15 months**)	X			
.709	.749	Vault Maintenance (**≥200 cubic feet**)(**1 per yr/15 months**)			X	
.603(b)	.751	Prevention of Accidental Ignition (hot work permits)	X			
.603(b)	.225(b)	Welding – Procedure	X			
.603(b)	.227/.229	Welding – Welder Qualification	X			
.603(b)	.243(b)(2)	NDT – NDT Personnel Qualification	X			
.709	.243(f)	NDT Records (**Pipeline Life**)	X			
.709		Repair: pipe (**Pipeline Life**); Other than pipe (**5 years**)	X			

Comments:
Gas is not odorized at Jackson Prairie, no pipelines have been abandoned, pressure limiting and regulators are on the LP distribution system operated by PSE for Lewis County, and there are no existing vaults greater than 200 cubic foot in size.

CORROSION CONTROL PERFORMANCE AND RECORDS			S	U	N/A	N/C
.491	.491(a)	Maps or Records	X			
.491	.459	Examination of Buried Pipe when Exposed	X			
.491	.465(a)	Annual Pipe-to-soil Monitoring (**1 per yr/15 months**)	X			
.491	.465(b)	Rectifier Monitoring (**6 per yr/2½ months**)	X			
.491	.465(c)	Interference Bond Monitoring – Critical (**6 per yr/2½ months**)			X	
.491	.465(c)	Interference Bond Monitoring – Non-critical (**1 per yr/15 months**)			X	
.491	.465(d)	Prompt Remedial Actions	X			
.491	.465(e)	Unprotected Pipeline Surveys, CP active corrosion areas (**1 per 3 cal yr/39 months**)			X	
.491	.467	Electrical Isolation (**Including Casings**)	X			
.491	.469	Test Stations – Sufficient Number	X			
.491	.471	Test Lead Maintenance	X			

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		CORROSION CONTROL PERFORMANCE AND RECORDS	S	U	N/A	N/C
.491	.473	Interference Currents	X			
.491	.475(a)	Internal Corrosion; Corrosive Gas Investigation			X	
.491	.475(b)	Internal Corrosion; Internal Surface Inspection; Pipe Replacement			X	
.476(d)	.476	Internal Corrosion Control: Design and construction of transmission line			X	
.491	.477	Internal Corrosion Control Coupon Monitoring (**2 per yr/7½ months**)	X			
.491	.481	Atmospheric Corrosion Control Monitoring (**1 per 3 cal yr/39 months onshore; 1 per yr/15 months offshore**)	X			
.491	.483/.485	Remedial: Replaced or Repaired Pipe; coated and protected; corrosion evaluation and actions	X			

Comments:
There are no interference bonds in place or unprotected pipelines. Internal corrosion control coupons are collected from the slug catcher and no known internal corrosion from pipe replacement. Low points near wellheads are designed to collect water from pipelines placed on a slope to drain to the low points.

	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 2008 Drug and Alcohol Program Check				

Recent PHMSA Advisory Bulletins (Last 2 years)

Leave this list with the operator.

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

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