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POST INSPECTION MEMORANDUM

Inspector: **Al Jones/WUTC 6/26/2012**
Reviewed: **Joe Subsits/WUTC, 6/27/2012**
Follow-Up Enforcement: **No Violations** ✓
~~**PCP* PCO* NOA WL LOC**~~
Director Approval* ____[illegible]____
12/18/12

Date: June 26, 2012

Operator Inspected: Northwest Pipeline Corp (WGP) **OPID:** 13845 **Region:** Western

Unit Address: 295 Chipeta Way
Salt Lake City, Utah 84108-1220

Unit Inspected:	Redmond	**Unit ID:**	3675
	Spokane	**Unit ID:**	8375
	Pasco	**Unit ID:**	8385
	Battle Ground	**Unit ID:**	8365
	Sumas	**Unit ID:**	8355

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Pipeline Safety Program

Unit Type: Interstate
Inspection Type: O07 - Team Integrity Management Program (IMP) Inspection
Record Location: Houston, TX and Salt Lake City, UT — Assign # 108415
Inspection Dates: 4/29/2012 through 5/4/2012 and 5/14-18/2012 (TX and UT)
5/29-31, 2012 (WA field validation) — Assign # 108416
AFOD: 11 (TX and UT), 3 (WA)
Assign # 102027
SMART Activity Number: 137168 [redacted]

PHMSA Contact: Derick Turner, Lead (OPS Atlanta, GA)
Phone: 404-832-1156 **Email:** derick.turner@dot.gov

Unit Description:
The IMP inspection was comprehensive for all of the above Districts for Williams Gas Pipelines located in Washington. The IMP protocols and HCA assessments were reviewed in Houston and Salt Lake City. The report prepared by VGO Testing & Inspection Engineers for Williams for a leak found on the North Seattle Lateral 8-inch line was reviewed. The crack was discovered during a hydro test at a reported pipe over-bend location. Additional mitigation to locate other sites for possible SCC cracks is being reviewed by Williams.

Facilities Inspected:
The meeting in Houston, Texas included the review of IMP Protocol Areas:

A. Identify HCA's
B. Baseline Assessment Plan
E. Remediation
F. Continual Evaluation & Assessment

The meeting in Salt Lake City Utah including the review of IMP Protocol Areas:

C. Threats and Risk Assessment
D. DA Plan
G. Confirmatory DA
H. Preventive & Mitigative Measures
K. Management of Change
M. Communications Plan

Persons Interviewed:

Steve Potts	713-215-2111
Sergio Limon	801-584-6787
David Katz	801-584-6911
Chris Mason	801-584-6689
Marie Sotak	713-215-2111
John Batehelder	713-215-2907
Stephanie Poole	713-215-2371
Larry Legendre	713-215-2733
Joe Neave	713-215-4811
Jason Lambert	801-584-6657
Stephanie Andrasko	713-215-2840
Jim Harrison	713-215-3033

IMP Team:

Derick Turner	Lead. OPS Atlanta
Robert Smallcomb	PHMSA - Eastern
Agustin Lopez	OPS - SW
Ross Reineke	OPS Western
Wayne Chan	PHMSA - Eastern
Bill Tzamos	PHMSA
Brian Kilduff	NYS DPS
Al Jones	WUTC

Probable Violations/Concerns: No probable violations noted at the time of this report.

Recommendations: Continue inspecting district in accordance with normal inspection cycle.

Comments:
The North Seattle lateral failure at MP 8 occurred during a hydrotest on the 8-inch diameter line in 2011. The leak was caused by a through-wall crack in the pipe. The pipe wall thickness is 0.188", API 5L grade X-42 material. The MAOP is 741 psi corresponding to 40% SMYS. The hydrotest pressure when the failure occurred was 1,339 psi (73% SMYS). According to the VGO Testing & Inspection Engineers report identified the failure mode as near neutral circumferential SCC. A 300 feet pipe section was replaced. In an email dated June 13, 2012 from Steve Potts included a report titled, "Addressing the Threat of Crack-like Indications on the North Seattle Lateral Line." The report referred to a 2003 Magnetic Flux Leakage (MFL) inspection with two dents and six corrosion callouts excavated and 2009 MFL and Transverse Flux Inspection (TFI) inspection with three seam weld and dent areas were excavated. Both ILI inspections did not find cracking indications. This summer, Williams plans to inspect several bends that will be removed during the upcoming expansion project. The expansion includes replacement of the first 2.2 miles of the 8" line with new 20" diameter pipe.

Attachments:
PHMSA Form-16 Gas IMP Field Verification Inspection for Spokane, WA
Exhibit A - Williams North Seattle Lateral Report
Exhibit B – Spokane pipe replacement photo

Version Date: 5/5/08

US Department of Transportation
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety

Gas IMP Field Verification Inspection
49 CFR Subparts 192.911, 192.921, 192.933, & 192.935

General Notes:

1. This Field Verification Inspection is performed on field activities being performed by an Operator in support of their Integrity Management Program (IMP).
2. This is a two part inspection form:
   i. A review of applicable Operations and Maintenance (O&M) and IMP processes and procedures applicable to the field activity being inspected to ensure the operator is implementing their O&M and IMP Manuals in a consistent manner.
   ii. A Field Verification Inspection to determine that activities on the pipeline and facilities are being performed in accordance with written procedures or guidance.
3. Not all parts of this form may be applicable to a specific Field Verification Inspection, and only those applicable portions of this form need to be completed. The applicable portions are identified in the Table below by a check mark. Only those sections of the form marked immediately below need to be documented as either "Satisfactory"; "Unsatisfactory"; or Not Checked ("N/C"). Those sections not marked below may be left blank.

Operator Inspected: Northwest Pipeline Corp (WGP)

Op ID: 13845

Perform Activity *(denoted by mark)*	Activity Number	Activity Description
	1A	In-Line Inspection
	1B	Hydrostatic Pressure Testing
	1C	Direct Assessment Technologies
	1D	Other Assessment Technologies
	2A	Remedial Actions
	2B	Remediation – Implementation
	3A	Preventive & Mitigative – additional measures evaluated for HCAs
	3B	Preventive & Mitigative – automatic shut-off valves
X	4A	Field Inspection for Verification of HCA Locations
	4B	Field Inspection for Verification of Anomaly Digs
X	4C	Field Inspection to Verify adequacy of the Cathodic Protection System
X	4D	Field inspection for general system characteristics
	attachment	Anomaly Evaluation Report
	attachment	Anomaly Repair Report

Gas IMP Field Verification Inspection Form

Name of Operator: Northwest Pipeline Corp (WGP)

Headquarters Address:
2800 Post Oak Blvd.
MC 1060/12314
Houston, TX 77056

Company Official: Randy Barnard, President

Phone Number: (713) 215-2375

Fax Number: (713) 215-2375

Operator ID: 13845

Persons Interviewed	Title	Phone No.	E-Mail
Scott Uribe	Operations Technician	509-544-9216	Scott.uribe@williams.com
Dustin Wallis	Pipeline Safety	(801) 584-6599	Dustin.Wallis@Williams.com

OPS/State Representative(s): Al Jones / UTC **Date(s) of Inspection:** May 29-31, 2012

Inspector Signature: ***Al Jones / UTC*** Date: June 26, 2012

Pipeline Segment Descriptions: *[note: Description of the Pipeline Segment Inspected as part of this field verification. (If information is available, include the pipe size, wall thickness, grade, seam type, coating type, length, normal operating pressure, MAOP, %SMYS, HCA locations, class locations, and Pipeline Segment boundaries.)]*

The Spokane District boundaries have changed since the last inspection. The current boundaries include Spokane, Lincoln, Grant, Adams, Whitman, and Franklin Counties. The transmission laterals have a MAOP of 811 psig except as noted for:
20" Spokane Line 55 miles from North Pasco to Ritzville
16" Spokane Line 62 miles from Ritzville to Spokane Mead Station
6" Coeur D'Alene Line 16 miles
30" Coeur D'Alene Line 14 miles
8" Moses Lake Lateral 38.2 miles
12" Lewiston Lateral 81 miles
6" Connell Lateral 4 miles
4" Othello Lateral 5.2 miles
2" Menan Starch Lateral 0.3 miles

Interconnections with TransCanada GTN:
20" Spokane Lateral 115 feet
12" Palouse Lateral 1 mile (1,018 psig MAOP)

The District has the following Class 3 Locations:
North Spokane off the west side of Barns Road

1.81 miles (MP 24.12 - 25.93)
1.88 miles (MP 26.16 - 28.05)
2.31 miles (MP 156.38 – 158.69)
4.23 miles (MP159.10 – 163.33)
0.03 mile (MP 0.26 – 0.29)

The District has one compressor station located at Mesa with one Solar Turbine rated at 1,340 HP.

Site Location of field activities: *[note: Describe the portion of the pipeline segment reviewed during the field verification, i.e. milepost/stations/valves/pipe-to-soil readings/river crossings/etc. In addition, a brief description and case number of the follow up items in any PHMSA compliance action or consent agreement that required field verification. Note: Complete pages 8 & 9 as appropriate.]*

The portion of unit inspected includes the main replacement in North Spokane, Washington between Nine Mile Falls and Spokane Mead Meter Stations, about 5.6 miles, 16-inch diameter, 0.250" wt, API 5L X52 pipe with Epoxy coating minimum 17 mils. The welding procedure and its qualification were reviewed at the Spokane District Office in accordance with Williams welding procedure and qualification of procedure (WPS No. SM G 2 and PQR No. SMAW-6301). The welders qualification from Snelson Construction and two NDT technicians from Quality Integrated Services were reviewed. Viewed NDT film for girth welds XR -69, -70, -71, -72, -73, -67, and repaired weld XR 67-R1. Reviewed 61 girth weld evaluated by NDT technicians. No concerns were noted in the procedure, qualification, or field data.

Summary:

This inspection was part of the IMP follow-up to field activities.

Findings:

Key Documents Reviewed:

Document Title	Document No.	Rev. No	Date
Reviewed 61 girth weld NDT test results			May 30, 2012

Part 1 - Performance of Integrity Assessments

1A. In-Line Inspection	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that Operator's O&M and IMP procedural requirements (e.g. launching/receiving tools) for performance of ILI were followed.			X	
Verify Operator's ILI procedural requirements were followed (e.g. operation of trap for launching and receiving of pig, operational control of flow), as appropriate.				
Verify ILI tool systems and calibration checks before run were performed to ensure tool was operating correctly prior to assessment being performed, as appropriate.				
Verify ILI complied with Operator's procedural requirements for performance of a successful assessment (e.g. speed of travel within limits, adequate transducer coverage), as appropriate.				
Document ILI Tool Vendor and Tool type (e.g. MFL, Deformation). Document other pertinent information about Vendor and Tool, as appropriate				
Verify that Operator's personnel have access to applicable procedures for preparing, running and monitoring the pipeline for ILI tools include performance requirements (e.g.: tool speeds, pipe cleanliness, operation of tool sensors, and ILI field calibration requirements), as appropriate.				*[Note: Add location specific information, as appropriate.]*
Other:				

1B. Hydrostatic Pressure Testing	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that hydrostatic pressure tests complied with Part 192 Subpart J requirements.			X	
Review documentation of Hydrostatic Pressure Test parameters and results. Verify test was performed without leakage and in compliance with Part 192 Subpart J requirements.				
Review test procedures and records and verify test acceptability and validity.				
Review determination of the cause of hydrostatic test failures, as appropriate.				
Document Hydrostatic Pressure Test Vendor and equipment used, as appropriate.				
Verify that the baseline assessment is conducted in a manner that minimizes environmental and safety risks (reference §192.919(e) and ADB-04-01)				
Other:				

1C. Direct Assessment Technologies	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that application of "Direct Assessment Technology" complied with Part 192.923			X	
Review documentation of Operator's application of "Direct Assessment Technology", if available. Verify compliance with Part 192.923 and Operator's procedural requirements, as applicable.				
Verify that appropriate tests and/or inspections are being performed and appropriate data is being collected, as appropriate.				
Other.				

1D. Other Assessment Technologies	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that application of "Other Assessment Technology" complied with Operator's requirements, that appropriate notifications had been submitted to PHMSA, and that appropriate data was collected.			X	
Review documentation of notification to PHMSA of Operator's application of "Other Assessment Technology", if available. Verify compliance with Operator's procedural requirements. If documentation of notification to PHMSA of Operator's application of "Other Assessment Technology" is available, verify performance of assessment within parameters originally submitted to PHMSA.				
Verify that appropriate tests are being performed and appropriate data is being collected, as appropriate.				
Other.				

Part 2 - Remediation of Anomalies

2A. Remedial Actions – Process	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that remedial actions complied with the Operator's procedural requirements.			X	
Witness anomaly remediation and verify documentation of remediation (e.g. Exposed Pipe Reports, Maintenance Report, any Data Acquisition Forms). Verify compliance with Operator's O&M Manual and Part 192 requirements.				
Verify that Operator's procedures were followed in locating and exposing the anomaly (e.g. any required pressure reductions, line location, identifying approximate location of anomaly for excavation, excavation, coating removal).				
Verify that procedures were followed in measuring the anomaly, determining the severity of the anomaly, and determining remaining strength of the pipe. Review the class location factor and failure pressure ratio used by Operator in determining repair of anomaly.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: ________________mV Off Potential: ________________mV
Verify that Operator's personnel have access to and knowledge of applicable procedures.				*[Note: Add location specific information and note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*
Other:				

2B. Remediation - Implementation	Satisfactory	Unsatisfactory	N/C	Notes:
Verify that the operator has adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis.			X	
If documentation is available, verify that repairs were completed in accordance with the operator's prioritized schedule and within the time frames allowed in §192.933(d).				
Review any documentation for this inspection site for an immediate repair condition (§192.933(d)(1)) where operating pressure was reduced or the pipeline was shutdown. Verify for an immediate repair condition that temporary operating pressure was determined in accordance with the requirements in §192.933(a) or, if not applicable, the operator should provide an engineering basis justifying the amount of pressure reduction.				
Verify that repairs were performed in accordance with §192.103, §192.111, §192.713, §192.717, §192.719, §192.933 and the Operator's O&M Manual, as appropriate. If welding is performed, verify a qualified welding procedure and qualified welders are used to perform repairs. If composite repair methods are used, verify that a method approved by the Operator is used, procedures are followed, and qualified personnel perform the repair.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: ________________mV Off Potential: ________________mV
Review CP readings at anomaly dig site, if possible. (See Part 4 of this form – "Field Inspection to Verify adequacy of the Cathodic Protection System" , as appropriate.				*[Note: Add location specific information and note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*
Other:				

Part 3 - Preventive and Mitigative Actions

3A. P&M Measures for Third Party Damage	Satisfactory	Unsatisfactory	N/C	Notes:
Identify additional measures evaluated for the HCA section of the pipeline and facilities.			X	
Verify that P & M measures regarding threats due to third party damage are being implemented: [§192.915(c), §192.935(b)(1)(iv)]:				
Confirm the use of qualified personnel for marking, locating, and direct supervision of known excavation work, as appropriate.				
Confirm the use of qualified personnel for monitoring of excavations conducted on covered pipeline segments by pipeline personnel, as appropriate.				
Other:				*[Note: Add location specific information, as appropriate.]*

3B. Installed Automatic Shut-off Valves (Protocol H.07)	Satisfactory	Unsatisfactory	N/C	Notes:
Verify additional preventive and mitigative actions implemented by Operator.			X	
Document that additional measures evaluated by the operator cover alternatives such as, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs, as appropriate				
Verify that the operator has a process to decide if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. [§192.935(c)]				
Verify operation of installed remote control valve by reviewing operator inspection/remote control records for partially opening and closing the valve, as appropriate.				
Other:				*[Note: Add location specific information, as appropriate.]*

Part 4 - Field Investigations (Additional Activities as appropriate)

4A. Field Inspection for Verification of HCA Locations	Satisfactory	Unsatisfactory	N/C	Notes:
Review HCAs locations as identified by the Operator. Utilize NPMS and Operator maps, as appropriate.	X			
Verify that the operator's integrity management program includes accurate and updated system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas, as appropriate. [§192.905(a)]				
Review the operator's applicable procedures and forms used to document new information from one-calls, surveys, aerial & ground patrols are being completed by field personnel to communicate new developments that may impact high consequence areas or that may create new high consequence areas to IM personnel, as appropriate. [§192.905(c)]				
Review the operator's applicable procedures and forms to confirm that new HCAs and class location changes are being identified through it's continuing surveillance program as required by §192.613 and §192.905.				*[Note: Add location specific information, as appropriate.]*

4B. Field Inspection for Verification of Anomaly Digs	Satisfactory	Unsatisfactory	N/C	Notes:
Verify repair areas, ILI verification sites, etc.			X	
Document the anomaly dig sites observed and reviewed as part of this field activity and the actions taken by the operator.				*[Note: Add location specific information, as appropriate.]*

4C. Field Inspection to Verify adequacy of the Cathodic Protection System	Satisfactory	Unsatisfactory	N/C	Notes:
In case of hydrostatic pressure testing, Cathodic Protection (CP) systems must be evaluated for general adequacy.	X			
The operator should review the CP system performance in conjunction with a hydrostatic pressure test to ensure the integrity assessment addressed applicable threats to the integrity of the pipeline. Has the operator reviewed the CP system performance in conjunction with the hydrostatic pressure test?				
Review records of CP readings from CIS and/or annual survey to ensure minimum code requirements are being met, if available.				Cathodic Protection readings of pipe to soil at dig site (if available): On Potential: ________________mV Off Potential: ________________mV
Review results of random field CP readings performed during this activity to ensure minimum code requirements are being met, if possible. Perform random rectifier checks during this activity and ensure rectifiers are operating correctly, if possible.				*[Note: Add location specific information and note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*

4D. Field inspection for general system characteristics	Satisfactory	Unsatisfactory	N/C	Notes:
Through field inspection determine overall condition of pipeline and associated facilities for a general estimation of the effectiveness of the operator's IMP implementation.	X			
Evaluate condition of the ROW of inspection site to ensure minimum code requirements are being met, as appropriate.				
Comment on Operator's apparent commitment to the integrity and safe operation of their system, as appropriate.				
Check ROW for pipeline markers in line-of-sight and Emergency call-in number on marker posts.				
Other:				

Anomaly Evaluation Report *(to be completed as appropriate)*

Pipeline System and Line Pipe Information	
Operator (OpID and System Name):	
Unit ID (Pipeline Name)	
Pipe Manufacturer and Year:	Seam Type and Orientation:
Pipe Nominal OD (inch):	Depth of Cover:
Pipe Nominal Wall thickness (inch):	Coating Type and Condition:
Grade of Pipe:	MAOP:
ILI Reported Information	
ILI Technology (e.g., Vendor, Tools):	
Anomaly Type (e.g., Mechanical, Metal Loss):	
Is anomaly in a segment that can affect an HCA? (Yes / No)	
Date of Tool Run (MM/DD/YY): Date of Inspection Report (MM/DD/YY):	
Date of "Discovery of Anomaly" (MM/DD/YY):	
Type of "Condition" (e.g.; Immediate; 60-day; 180-day):	
Anomaly Feature (Int/Ext): Orientation (O'clock position):	
Anomaly Details: Length (in): Width (in): Depth (in):	
Anomaly Log Distance (ft): Distance from Upstream weld (ft):	
Length of joint(s) of pipe in which anomaly is identified (ft):	
Anomaly Dig Site Information Summary	
Date of Anomaly Dig (MM/DD/YY):	
Location Information (describe or attach map):	
Mile Post Number: Distance from A/G Reference (ft):	
Distance from Upstream weld (ft):	
GPS Readings (if available) Longitude: Latitude:	
Anomaly Feature (Int/Ext): Orientation:	
Length of joint of pipe in which anomaly is found (ft):	
For Mechanical Damage Anomaly	
Damage Type (e.g., original construction, plain dent, gouge):	
Length (in): Width (in): Depth (in):	
Near a weld? (Yes / No):	
Gouge or metal loss associated with dent? (Yes / No): Are multiple dents present? (Yes / No):	
Did operator perform additional NDE to evaluate presence of cracks in dent? (Yes / No):	
Cracks associated with dent? (Yes / No):	
For Corrosion Metal Loss Anomaly	
Anomaly Type (e.g., pitting, general):	
Length (in): Width (in): Max. Depth (in):	
Remaining minimum wall thickness (in): Maximum % Wall Loss measurement(%):	
Safe pressure calculation (psi), as appropriate:	
For "Other Types" of Anomalies	
Describe anomaly (e.g., dent with metal loss, crack, seam defect, SCC):	
Length (in): Width (in): Max. Depth (in):	
Other Information, as appropriate:	
Did operator perform additional NDE to evaluate presence of cracks? (Yes / No):	
Cracks present? (Yes / No):	

Anomaly Repair Report *(to be completed as appropriate)*

Repair Information
Was a repair of the anomaly made? (Yes / No): Was Operating Pressure Reduced per 192.933(a) requirements?
Was defect ground out to eliminate need for repair? (Yes / No):
If grinding used, complete the following for affected area: Length (in): Width (in): Depth (in):
If NO repair of an anomaly for which RSTRENG/B31.G is applicable, were the Operator's RSTRENG/B31.G calculations reviewed? (Yes / No):
If Repair made, complete the following:
Repair Type (e.g., Type B-sleeve, composite wrap)
Was defect ground out prior to making repair? (Yes / No):
Operating Pressure at the time of repair:
Length of Repair: Pipe re-coating material used:
Comments on Repair material, as appropriate (e.g., grade of steel, wall thickness):
Comments on Repair procedure, as appropriate (e.g., welded sleeve, composite wrap):
General Observations and Comments
Was a diagram (e.g., corrosion map) of the anomaly made? (Yes / No): (Include in report if available)
Were pipe-to-soil cathodic protection readings taken? (Yes / No):
If CP readings taken, Record: On Potential: ______________mV; Off Potential: ________________mV *[Note: Note whether CP readings were from the surface or from the pipe following exposure, as appropriate.]*
Describe method used by Operator to locate anomaly (as appropriate):
Comments regarding procedures followed during excavation, repair of anomaly, and backfill (as appropriate):
General Observations and Comments *(Note: attach photographs, sketches, etc., as appropriate)*:

Williams Gas Pipeline (WGP) -West

Addressing the Threat of Crack-like Indications on the North Seattle Lateral Line

BACKGROUND

The 8" North Seattle Lateral was originally constructed in 1956 and is 11.1 miles long. The pipeline was constructed using 8 5/8" O.D., 0.188"wall thickness, X42 ERW pipe manufactured by Kaiser. MAOP is 809 psig (44% P_{SMYS}), but this higher pressure only affects the first 0.6 miles as downstream of this point, regulators are set at 550 psig (30% P_{SMYS}). This line is also odorized downstream of Mile Post (MP) 0.6. The first 2.2 miles of the original 8" will be replaced with new 20" diameter pipe this summer from MP 0.0 to MP 2.2 as part of a capacity expansion project. In addition, the PSE (Puget Sound Energy) regulator station at MP 10.38 is set to 250 psig, therefore, the last ¾ mile will be limited to 14 % P_{SMYS}.

The 8" North Seattle Lateral has been In Line Inspected (ILI) twice. The first run in 2003 used a Magnetic Flux Leakage (MFL) tool; two dents and six corrosion callouts were excavated with no cracking found using Magnetic Particle Inspection (MPI). In 2009, an MFL tool and a Transverse Field Inspection (TFI) circumferential MFL tool were run. Based on the ILI data, three seam weld and dent areas were addressed, again finding no cracking. One corrosion site was investigated requiring only recoat; no cracking was found.

In 2011, Williams conducted a pressure test of the 8" North Seattle Lateral to address the seam weld integrity issue and to supplement the previous circumferential MFL ILI tool run. During the first hydrostatic test, the pipe pressure declined approximately 15 psig per hour and the pressure never stabilized. The test pressure reached 1330 psig. The leak was difficult to locate so Williams used a technology that froze the water inside the pipe (freeze plugs) to allow pipe sections to be isolated and then re-pressured to isolate the leak location. After beginning excavation near North Creek (MP 8.1), a leak was found (circumferential crack-like feature) and a 71.6' section of pipe was replaced above the creek. The pipe sections at the freeze plug locations and leak site were sent to VGO Testing & Inspection Engineers lab in Portland, Oregon for analysis. A freeze plug was then installed on the east side of North Creek. After installing the plug, the pressure dropped 5 psig every 30 minutes, so WGP decided to replace the pipe on both sides of the creek. Since salmon were in the creek, a span was installed. In all, 314' of pipe was replaced. All replaced pipe was magnetic particle inspected and no additional indications were found. The original pipe crossing the creek was left abandoned in place due to the salmon. Subsequently, the 8" line was successfully hydrotested.

INTEGRITY ASSESSMENT PLAN FOR ADDRESSING THE THREAT OF CRACK-LIKE INDICATIONS

WGP plans the following steps to ensure continued safe operations on the 8 inch North Seattle Lateral:

WGP has completed the ILI data set review looking for similar indications to the two leaks near North Creek. No additional unique signals were found. This is likely due to the tightness and orientation of the cracking.

WGP has conducted preliminary engineering analysis and determined that the fatigue life of any remaining defects is well over 50 years - based on the pressure cyclic data obtained from SCADA. Circumferential crack growth rates are significantly slower than crack growth rates of the more conventional axially-oriented environmental cracking (approximately 0.011 inches per year[1]) due to the fact that circumferentially-oriented cracks are not subjected to much hoop stress from pressure fluctuations or spike hydrostatic testing (approx. ½ the stress in the circumferential direction as vs. the axial direction). Even if using the more aggressive 0.011 inches per year growth rate for axially-oriented cracking, over 17 years would be required to grow an existing crack to failure.

WGP plans to inspect several bends that will be removed during the upcoming expansion project. The expansion includes replacement of the first 2.2 miles of the 8" line with new larger diameter pipe.

A more detailed independent engineering analysis will be conducted as a follow-up to the preliminary analysis. After inspection of the replacement related bends, WGP will determine if additional excavations are needed to confirm either the engineering analysis or inspection findings.

Depending on the above analysis, WGP plans to re-hydrostatic test this line in 5 – 7 years and will continue to evaluate improvements in ILI technology to detect circumferential cracking in this small diameter pipe. The external corrosion threat will likely be re-assessed with ILI at the time of the next hydrostatic test. These assessment plans have been added to the Williams Baseline Assessment Plan.

Due to the low operating pressures on this 8" pipeline, the circumferential orientation of the defects, and the desire to not subject pre-1970 ERW seams to unnecessarily high stress levels, a spike test was neither warranted nor recommended.

Footnote 1

Excerpted from Williams 26 inch CAO documents submitted to PHMSA in 2011: "Crack growth rates based on the comparison of the two ILI runs indicated a growth rate of 0.011"/yr; much less aggressive than the originally estimated 0.033"/year. This growth rate also is in line with other operator's reported data from repeated Crack Detection tool run comparisons (0.01 – 0.016"/year)."

Exhibit B - Spokane, WA
Class 3 Location – 16-inch line replacement
Photo: Al Jones 6/6/2012