Final PHMSA Recommended Conditions for Keystone XL State Dept. Presidential Permit

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The Pipeline and Hazardous Materials Safety Administration (PHMSA) recommends that the U.S. Department of State impose the following conditions if a Presidential Permit will be granted to TransCanada Keystone Pipeline, LP ("Keystone") to construct and operate the Keystone XL Pipeline ("Keystone XL" or the "pipeline"). Specifically, the State Department should require Keystone to include all of the following in its written design, construction, and operating and maintenance plans and procedures:

I. Material Requirements

1) Steel Properties: The skelp/plate must be micro-alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.

2) Manufacturing Standards: Pipe must be manufactured according to American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L 44th Edition), product specification level 2 (PSL 2), supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23% based on the material chemistry parameter, carbon equivalent (CE) (Pcm) formula (Ito-Bessyo formula) or 0.40% based on the C-IIW formula (International Institute of Welding formula).

3) Fracture Control: API 5L and other specifications and standards addressing the steel pipe toughness properties needed to resist crack initiation, crack propagation and to ensure crack arrest during a pipeline failure caused by a fracture must be followed. Keystone must prepare and implement a fracture control plan addressing the steel pipe properties necessary to resist crack initiation and crack propagation. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan must be in accordance with API 5L (44th Edition) and include the following tests:

a) Fracture Toughness Testing for Shear Area: Test results must indicate at least 85% minimum average shear area per test for all X- 70 heats and 85% minimum shear area for all X- 80 heats with a minimum result of 80% shear area for any single test. The test results must also ensure a ductile fracture and arrest;
b) Fracture Toughness Testing for Absorbed Energy in accordance with Annex G and a minimum of 50 ft-lbs per heat on a full sized specimen at -5 degrees C/23 degrees F; and
c) Fracture Toughness Testing by Drop Weight Tear Test for All New Pipeline Segments or Pipe Replacements: Test results must be at least 85% of the average shear area for all heats with a minimum result of 60% of the shear area for any single test. The test results must also ensure a ductile fracture and arrest.

The above fracture control plan must account for the entire range of pipeline operating temperatures, pressures and product compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions. Where the use of stress factors, pipe grade, operating temperatures and product composition make fracture toughness calculations non-conservative, correction factors must be used.

4) Steel – Plate, Coil or Skelp Quality Control and Assurance: Keystone must prepare and implement an internal quality management program at all mills involved in producing steel plate, coil, skelp, and pipe to be operated in the pipeline. These programs must be structured to detect and eliminate defects, inclusions, non-specification yield strength, and tensile strength properties, and chemistry as affecting pipe quality.

a) A mill inspection program or internal quality management program must include the following:

(i) Non-destructive test of the ends and at least 35 percent of the surface of the plate, coil or pipe shall be performed to identify imperfections such as laminations, cracks, and inclusions that may impair serviceability. 100 percent of the pipe sections must be tested. Surface ultrasonic shall be done in accordance with American Society of Testing and Materials (ASTM) A578/A578M Level B or equivalent, to acceptance Level B. Pipe ends shall be inspected by ultrasonic, magnetic particle or liquid penetrant methods, with acceptance criteria as outlined in Clause 9.10.4 or API 5L (44th Edition).

(ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process shall be performed. Use of sulfur prints is not an equivalent method. The test must be carried out on a slab from the first heat of each sequence, and graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent;

(iii) A quality assurance monitoring program implemented by the operator shall include evaluations of:

a. all steelmaking and casting facilities;
b. quality control plans and manufacturing procedure specifications;
c. equipment maintenance and records of conformance;
d. procedures for controls on superheat and casting speeds, steel rolling temperatures and cooling temperatures;
e. additional mechanical and chemical properties tests based upon steel grade, plate or coil, and must be selected based upon knowledge of patterns of property variability in the coils and plate based upon the steel making process and rolling and cooling temperatures to assure that steel properties are not variable;
f. A verification program to ensure the pipe mill is taking into account all yield and tensile strength losses that may occur in the coiling and pipe rolling processes to ensure that the finished pipe has yield and tensile strengths that meet API 5L specifications;
g. Coils and plate with casting and rolling process deviations that may affect steel properties must have a re-verification of

mechanical and chemical properties on the pipe heat conducted at pipe location to ensure there are no variability in the pipe;

h. The pipe supplier must notify Keystone of all instances that do not meet the above items prior to supplying the pipe to Keystone; and

i. Procedures for centerline segregation monitoring to ensure mitigation of centerline segregation during the continuous casting process.

(iv) Pipe end tolerances must be applied so that there are no flat spots on the pipe that could affect welding quality. From each pipe mill, the end tolerances on pipe diameter must not exceed the range given in API 5L, Forty-Fourth (44^{th}) Edition, Table 10, for any given pipe wall thickness. Keystone must demonstrate compliance with API 5L 44^{th} Edition Table 10 by providing to the appropriate PHMSA Region Director(s), Central, Western, and Southwest Region, a histogram of end tolerance and wall thickness data representing physical evidence of compliance for a minimum of 10% of the pipe manufactured by each pipe mill facility.

(v) During construction, if pipe supplied from varying pipe mills cannot be preferentially strung, histograms and field weldability tests should be conducted to ensure that excessive high low is not in production/field welds.

5) Pipe Seam Quality Control: Keystone must prepare and implement a quality assurance program for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API 5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness (Hv10). The hardness tests must include a minimum of three (3) readings for each heat

affected zone, three (3) readings in the weld metal and two (2) readings in each section of pipe base metal for a total of thirteen (13) readings. The pipe weld seam must be 100% UT inspected after expansion and hydrostatic testing per APL 5L.

6) Monitoring for Seam Fatigue from Transportation: Keystone must inspect the double submerged arc welded seams of the delivered pipe using properly calibrated manual or automatic ultrasonic testing techniques. For each lay down area, a minimum of one (1) pipe section from the bottom layer of pipes of the first five (5) rail car shipments from each pipe mill must be inspected. For longitudinal weld seams, the entire seam must be tested. For helical seam submerged arc welded pipe, the weld seam in the area along the transportation bearing surfaces and all other exposed welded areas during the test must be tested. All the results must be appropriately documented. Each pipe section test record must be traceable to the pipe section tested.

7) Puncture Resistance: Steel pipe must be puncture resistant to an excavator weighing up to 65 tons with a general purpose tooth size of 3.54 inches by 0.137 inches. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's *Reliability Based Prevention of Mechanical Damage to Pipelines* calculation method.

8) Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test pressure of 95% SMYS or greater for 10 seconds. The 95% stress level may be achieved using a combination of internal test pressure and the application of end loads imposed by the hydrostatic testing equipment as allowed by API 5L, Clause 10.2.6.6.

9) Pipe Coating: The application of a corrosion resistant coating to the steel pipe must be performed according to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair. All pipe must be protected against external corrosion by non-shielding: coatings, repair coatings and protective

material used to protect the pipe from rock damage. Holiday detection must include appropriate calibration of jeeping equipment on a holiday that extends through the coating to the metal of the pipe to be jeeped prior to use each working day. Jeeping voltages must be set at a minimum of twenty-five hundred Volts (2500 V) for fusion bond epoxy (FBE), with higher voltages to be considered based on the coating type, thickness (maximum and minimum), grounding and field conditions that day. For other coatings, minimum voltage settings need to be established by determining the nominal coating thicknesses and coating type. The pipe should be free of any excess debris prior to running the jeeping equipment over the area. Visual inspection for holidays and coating damage should complement the use of jeeping equipment.

All pipe coating must be checked by usage of holiday detection equipment prior to backfill and FBE coated pipe must be checked with holiday detection equipment set at a minimum of twenty-five hundred Volts (2500 V) prior to backfill. All coating defects must be repaired and re-checked prior to backfill. To the extent practicable, Keystone shall jeep the coating at the same voltage in the coating mill as in the field.

II. Construction Requirements

10) Field Coating: Keystone must implement field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection and repair quality. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid qualified coating procedures and be trained to use these procedures. Holiday detection must include appropriate calibration of jeeping equipment on a holiday that extends through the coating to the metal of the pipe to be jeeped prior to use each working day. Jeeping voltages must be set at a minimum of twenty-five hundred Volts (2500 V) for FBE, with higher voltages to be considered based on the grounding and field conditions that day. For other coatings such as for girth weld coatings, minimum voltage settings need to be established by determining the nominal coating thicknesses (maximum and minimum) and type coating used for application. The pipe should be free

of any excess debris prior to running the jeeping equipment over the area. Visual inspection for holidays and coating damage should complement the use of jeeping equipment.

11) Coatings for Trenchless Installation: Coatings used for directional bore, slick bore and other trenchless installation methods must be capable of resisting abrasion and other damage that may occur due to rocks and other obstructions encountered in this installation technique.

12) Bends Quality: Keystone must obtain and retain certification records of factory induction bends and factory weld bends. All bends, flanges and fittings must have carbon equivalents (CE) equal to or below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42 on the CE-II W Formula (International Institute of Welding formula).

13) Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and pumps) must be rated for a pressure rating commensurate with the Maximum Operating Pressure (MOP) of the pipeline.

14) Pipeline Design Factor - Pipelines: Pipe installed must comply with the 0.72 design factor in 49 CFR § 195.106.

    a) At least six (6) months prior to beginning construction of the Keystone XL pipeline, Keystone must review with the appropriate PHMSA Regional Directors in Central, Western, and Southwest Regions how High Consequence Areas (HCAs) which could be affected, as defined in 49 CFR § 195.450, were determined (including commercial navigable waterways, high population areas, other populated areas, and unusually sensitive areas, including aquifers as defined in 49 CFR §195.6) were determined, and the design of the pipeline associated with those segments. Keystone must identify piping and the design of piping located within pump stations, mainline valve assemblies, pigging facilities, measurement facilities, road crossings, railroad crossings, and segments operating immediately downstream and at lower elevations than a pump station. Keystone must also provide any overland spread analyses in accordance with § 195.452(f) to support could affect determinations for water bodies more than 100 feet wide from high-water mark to high-water mark.

b) Post construction, Keystone must conduct a yearly survey, not to exceed fifteen (15) months, to identify any changes on the pipeline system that would impact its designation or design.

15) Temperature Control: Normal pump discharge temperatures should remain at or below 120° Fahrenheit (°F). If the temperature exceeds 120° F, Keystone must prepare and implement a coating monitoring program in these areas, using ongoing Direct Current Voltage Gradient (DCVG) surveys or Alternating Current Voltage Gradient (ACVG) surveys, or other testing to demonstrate the integrity of the coating. Non-continuous discharge temperature "spikes" above 120 °F for less than ½ day duration will not be a cause for implementing the procedure, but Keystone must inform the appropriate PHMSA Regional Director if regular operation above 120 °F at pump station discharges will occur. Under no circumstances may the pump station discharge temperatures exceed 150° Fahrenheit (°F) without sufficient justification that Keystone's long-term operating tests show that the pipe coating will withstand the higher operating temperature for long-term operations, and approval from the appropriate PHMSA region(s).

Pump Station Discharge Temperature – operating above 120° F and up to 150° F maximum, fusion bond epoxy (FBE) coating:

a) Keystone must monitor coating performance in areas where operating temperatures have exceeded or will exceed 120° F to provide additional data on the long-term durability and integrity of FBE coatings at these temperatures. Cathodic protection (CP) current requirements and coating surveys with DCVG (soil cover) and ACVG (pavement cover) will indicate if there is deterioration in the coating at the higher temperatures.

b) For DCVG and ACVG coating evaluation survey results will be addressed as follows:

The threshold survey indication values are thirty-five percent (35%) IR for DCVG and 50dBμV for ACVG. These values represent the mid range of the "Minor" category in the severity classification used to characterize survey indications in an ECDA program.

c) Keystone shall excavate and remediate all indications found above the threshold values – Minor, Moderate and Severe categories.

d) Keystone shall conduct a calibration dig on at least two anomalies of each classification that are classified as minor, moderate and severe to ensure findings that are not in the remediation plan are not detrimental to the pipeline.

e) Keystone shall perform Holiday voltage tests (jeep), coating adhesion and coating cure tests at excavations.

f) Keystone shall remove disbonded or blistered coating (with cracking and other damage that will compromise cathodic protection) found during excavations and shall apply new coating.

g) Keystone shall perform baseline DCVG two and a half (2-1/2) years and five (5) years after operating above 120° F, and in concert with future in-line inspection (ILI) and close-interval (CIS) surveys, both initial and second ILI tool runs, not to exceed 90 days before or past the schedule interval.

h) Keystone shall monitor surface temperatures of the pipe during winter and summer operating conditions at '0' miles and at a downstream mileage to assure that the surface temperatures do not exceed 120° F. If it is determined that the temperature at this point exceeds 120° F, the survey distance will be increased to the point where the temperature is below 120° F. Keystone must survey based upon temperature measurements or a minimum of twenty (20) miles downstream of each pump station operating above 120° F.

i) Keystone shall make repairs to FBE coatings with a compatible coating system that will bond together, be resistant to soil stresses, and not shield cathodic protection.

16) Overpressure Protection Control: Keystone must limit mainline pipeline overpressure protection to a maximum of 110% maximum operating pressure (MOP) during surge events consistent with 49 CFR § 195.406(b). Before commencing operation, Keystone

must perform a surge analysis showing how the pipeline will be operated to be consistent with these overpressure protection conditions. Keystone shall equip the pipeline with field devices to prevent overpressure conditions. Remotely actuated valves should be fitted with devices that will stop the transit (intentional or uncommanded) of the mainline valve should an overpressure condition occur or an impending overpressure condition is expected. Sufficient pressure sensors, on both the upstream and downside side of valves, must be installed to ensure that an overpressure situation does not occur. Sufficient pressure sensors shall be installed along the pipeline to conduct real time hydraulic modeling, and which can be used to conduct a surge analysis to determine whether pipeline segments have experienced an overpressure condition.

17) Construction Plans and Schedule: At least ninety (90) days prior to the anticipated construction start date, Keystone must submit its construction plans and schedule to the appropriate PHMSA Directors in Central, Western, and Southwest Regions for review. Subsequent plans and schedule revisions must also be submitted to the appropriate Directors, PHMSA Central, Western, and Southwest Regions on a monthly basis.

18) Welding Procedures for All New Pipeline Segments or Pipe Replacements: For automatic or mechanized welding, Keystone shall use the 20th Edition of American Petroleum Institute 1104 (API 1104), *"Welding of Pipelines and Related Facilities"* for welding procedure qualification, welder qualification and weld acceptance criteria. Keystone shall use the 20th Edition of API 1104 for all other welding processes. At least twenty-one (21) days prior to the beginning of any welding procedure qualification activities, Keystone shall notify the appropriate PHMSA Directors in Central, Western, and Southwest Regions. Keystone shall submit automated or manual welding procedure documentation to the same PHMSA regional office.

a) Should non-destructive testing of field girth welds be conducted by usage of automated ultrasonic testing (AUT) API 1104, Appendix A, Keystone must conduct stress analysis for the welding procedures as required in API 1104, Appendix A, Paragraph A.2.

b) Should API 1104, Appendix A, be used for welding, Keystone must conduct individual procedure tests for each steel supplier and for each girth weld with mixed steel suppliers.

c) All welding procedures, AUT procedures and pipe lifting procedures for field construction crews must be documented in construction procedures and field construction crews must be trained in the procedure requirements prior to conducting welding and girth weld AUT in accordance with API 1104, Appendix A.

d) Keystone shall nondestructively test all girth welds in accordance with 49 CFR §§ 195.228, 195.230 and 195.234.

19) Depth of Cover: Keystone shall construct the pipeline with soil cover at a minimum depth of forty-eight (48) inches in all areas, except in consolidated rock. The minimum depth in consolidated rock areas is thirty-six (36) inches. Keystone shall maintain a depth of cover of 48 inches in cultivated areas and a depth of 42 inches in all other areas. In cultivated areas where conditions prevent the maintenance of forty-eight (48) inches of cover, Keystone must employ additional protective measures to alert the public and excavators to the presence of the pipeline. The additional measures shall include:

a) Placing warning tape and additional line-of-sight pipeline markers along the affected pipeline segment,

b) In areas where threats from chisel plowing or other activities are threats to the pipeline, the top of the pipeline must be installed and maintained at least one foot below the deepest penetration above the pipeline, not to be less than 42-inches of cover.

If a routine patrol (ground and/or aerial) or other observed conditions during maintenance, where farming, excavation, or construction activities are ongoing, or after weather events occur, indicate the possible loss of cover over the pipeline, Keystone must perform a depth of cover study and replace cover as soon as practicable, not to exceed six (6) months, to meet the minimum depth of cover requirements specified herein.

In addition to any depth of cover maintenance activities that may take place as a result of routine patrols, Keystone must perform a detailed depth of cover survey along the entire Keystone XL pipeline as frequently as practicable, not to exceed once every ten (10) years, and replace cover as soon as practicable, not to exceed six (6) months, to meet the minimum depth of cover requirements specified herein.

20) Construction Tasks: Keystone must prepare and follow an Operator Qualification (OQ) Program for construction tasks that can affect pipeline integrity. The Construction OQ program must comply with 49 CFR § 195.501 and must be followed throughout the construction process for the qualification of individuals performing tasks on the pipeline.

If the performance of a construction task can affect the integrity of the pipeline segment, the operator must treat that task as a "covered task," notwithstanding the definition in 49 CFR § 195.501(b), and must implement the requirements of Subpart G. Keystone shall retain qualification records for each individual performing covered tasks during and after the construction of the pipeline, whether company or contract employee.

Keystone must prepare and follow a construction quality assurance plan, to ensure quality standards and controls of the pipeline, throughout the construction phase. Such a plan shall include, at a minimum, provisions for the following: pipe inspection (at the last pipe shipping or storage location prior to stringing on the construction right of way, whether rail yard or pipe storage yard), hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. These tasks can affect the integrity of the pipeline segment and must be treated as covered tasks. The individuals driving the pipe stringing trucks to the pipeline ROW would not need to be OQ qualified, unless they are responsible for the pipe unloading.

Other tasks that can affect pipeline integrity which must be treated as covered tasks include, but are not limited to, surveying, locating foreign lines, one call notifications, ditching, alternating current (AC) interference mitigation and mitigation, cathodic protection (CP) system surveys, mitigation and installation, conducting directional drills, anomaly evaluations and repairs, right of way clean up (including installation of line markers), and quality assurance monitoring.

Keystone must provide its construction OQ plan to the appropriate PHMSA Regional Director for review prior to beginning construction.

All girth welds must be inspected, repaired and non-destructively examined in accordance with 49 CFR §§ 195.228, 195.230 and 195.234. The NDE examiner must have all required and current certifications.

21) Interference Currents Control: Control of induced AC from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to the attention of the applicable PHMSA Director(s) in Central, Western, and Southwest Regions. Within six (6) months after placing the pipeline in service, Keystone must develop and implement an induced AC program to protect the pipeline from corrosion caused by stray currents.

22) Pressure Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100% SMYS for mainline pipe and 1.39 times MOP for pump stations for eight (8) continuous hours. The hydrostatic test results from each test must be submitted in electronic format to the applicable PHMSA Director(s) in PHMSA Central, Western and Southwest Regions after completion of each pipeline.

23) Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the applicable PHMSA Director(s) in Central, Western, and Southwest Regions within 60 days of the failure.

III. Operations and Maintenance

24) Supervisory Control and Data Acquisition (SCADA) System: Keystone must develop and install a SCADA system to provide remote monitoring and control of the entire pipeline system.

25) SCADA System – General:

a) Scan rate shall be fast enough to minimize overpressure conditions (overpressure control system), provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations.

b) Must meet the requirements of regulations developed as a result of the findings of the National Transportation Safety Board (NTSB), *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines,* Safety Study, NTSB/SS-05/02 specifically including:

i) Operator displays shall adhere to guidance provided in American Petroleum Institute Recommended Practice 1165 (API 1165 - *First Edition)*, *Recommended Practice for Pipeline SCADA Displays.* This shall be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual is assigned the responsibility to monitor and respond to SCADA information (tanks terminals or facilities also).

ii) Operators must have a policy for the review and audit of alarms for false alarm reduction and near miss or lessons learned criteria. This alarm review shall be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (tanks terminals or facilities also).

iii) SCADA controller training shall include simulator for controller recognition of abnormal operating conditions, in particular leak events. A generic simulator or simulation shall not be allowed by itself as a means to meet this requirement. A full simulator (console screens respond and react as actual console screens) shall be required and used for training of abnormal operating conditions (AOC's) wherever possible.

iv) See item 29(b) below on fatigue management.

v) Install computer-based leak detection system on all lines unless an engineering analysis determines that such a system is not necessary.

c) Develop and implement shift change procedures for controllers that are scientifically based, sets appropriate work and rest schedules, and consider circadian rhythms and human sleep and rest requirements in-line with guidance provided by NTSB recommendation P-99-12 issued June 1, 1999.

d) Verify point-to-point display screens and SCADA system inputs before placing the line in service. This shall be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (tanks terminals or facilities also).

e) Implement individual controller log-in provisions.

f) Establish and maintain a secure operating control room environment.

g) Establish and maintain the ability to make modifications and test these modifications in an off-line mode. The pipeline must have controls in-place and be functionally tested in an off-line mode prior to any changes being implemented after the line is in service and prior to beginning the line fill stage.

h) Provide SCADA computer process load information tracking.

26) SCADA – Alarm Management: Alarm Management Policy and Procedures shall address:

a) Alarm priorities determination.

b) Controllers' authority and responsibility.

c) Clear alarm and event descriptors that are understood by controllers.

d) Number of alarms.

e) Potential systemic system issues.

f) Unnecessary alarms.

g) Controller's performance regarding alarm or event response.

h) Alarm indication of abnormal operating conditions (AOCs).

i) Combination AOCs or sequential alarms and events.

j) Workload concerns.

k) This alarm management policy and procedure review shall be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (such as for tanks, terminals, or other associated facilities).

27) SCADA – Leak Detection System (LDS): The LDS Plan shall include provisions for:

a) Implementing applicable provisions in American Petroleum Institute Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines,* (API RP 1130, 1st Edition 2007).

b) Addressing the following leak detection system testing and validation issues:

(1) Routine testing to ensure degradation has not affected functionality

(2) Validation of the ability of the LDS to detect small leaks and modification of the LDS as necessary to enhance its accuracy to detect small leaks.

(3) Conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection.

c) Developing data validation plan (ensure input data to SCADA is valid)

d) Defining leak detection criteria in the following areas:

(1) Minimum size of leak to be detected regardless of pipeline conditions (slack, transient, etc., as related to the Keystone XL pipeline configuration.

(2) Leak location accuracy for various pipeline conditions.

(3) Response time for various pipeline conditions.

e) Providing redundancy plans for hardware and software and a periodic test requirement for equipment to be used live (also applies to SCADA equipment).

28) SCADA – Pipeline Model and Simulator: The Thermal-Hydraulic Pipeline Model/ Simulator including pressure control system shall include a Model Validation/Verification Plan.

29) SCADA – Training: The training and qualification plan (including simulator training) for controllers shall:

a) Emphasize procedures for detecting and mitigating leaks.

b) Include a fatigue management plan and implementation of a shift rotation schedule that minimizes possible fatigue concerns and is scientifically based, sets appropriate work and rest schedules, and consider circadian rhythms and human sleep and rest requirements in-line with NTSB recommendation P-99-12 issued June 1, 1999.

c) Define controller maximum hours of service limitations.

d) Meet the requirements of regulations developed as a result of the guidance provided in the American Society of Mechanical Engineers Standard B31Q, *Pipeline Personnel Qualification Standard* (ASME B31Q), September 2006, for developing qualification program plans.

e) Include and implement a full training simulator capable of replaying for training purposes near miss or lesson learned scenarios.

f) Implement tabletop and field exercises no less than five (5) times per year that allow controllers to provide feedback to the exercises, participate in exercise scenario development and be active participants in the exercise.

g) Include field visits for controllers accompanied by field personnel who will respond to call outs for that specific facility location.

h) Provide facility specifics in regard to the position certain equipment devices will default to upon power loss.

i) Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status. This review shall be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (such as for tanks, terminals, or other associated facilities).

j) Task specific abnormal operating conditions and generic abnormal operating conditions training components.

k) If controllers are required to respond to "800" calls, include a training program conveying proper procedures for responding to emergency calls, notification of other pipeline operators in the area when affecting a common pipeline corridor and education on the types of communications supplied to emergency responders and the public using API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators,* (API RP 1162 (1st edition, December 2003) or the most recent version incorporated in 49 CFR § 195.3).

l) Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction.

m) Implement a substantiated qualification program for re-qualification intervals addressing program requirements for what circumstances will result in qualifications being revoked; implementing procedure documentation regarding how long a controller can be absent before a period of review; shadowing, retraining, or re-qualification is required, and addressing interim performance verification measures between re-qualification intervals.

30) SCADA – Calibration and Maintenance: The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in American Petroleum Institute Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines,* (API RP 1130, 1st Edition 2007). Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall periodically be reviewed for concerns regarding mechanical problems. This information shall be tracked and prioritized. Maintenance of field related instrumentation repairs affecting SCADA data (local or remote) shall also be tracked, prioritized and documented at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (such as for tanks, terminals, or other associated facilities).

31) SCADA – Leak Detection Manual: The Leak Detection Manual shall be prepared using guidance provided in Canadian Standards Association (CSA), *Oil and Gas Pipeline Systems*, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual.

32) Mainline and Check Valve Control: Keystone must design and install mainline block valves and check valves on the Keystone XL system based on the worst case discharge as calculated by 49 CFR § 194.105. Keystone shall locate valves in accordance with 49 CFR § 195.260 and by taking into consideration elevation, population, and environmentally sensitive locations, to minimize the consequences of a release from the pipeline. Mainline valves must be placed based on the analysis above or no more than twenty (20) miles apart, whichever is smaller. Mainline valves must contain transit inhibit switches that prevent the valves from shutting at a rate (and in conjunction with pumps being shutdown) so that no pressure surges can occur, or other damage caused by unintended valve closures or too fast of a closure.

Valves must be remotely controlled and actuated, and the SCADA system must be capable of closing the valve and monitoring the valve position, upstream pressure and downstream pressure so as to minimize the response time in the case of a failure. Remote power backup is required to ensure communications are maintained during inclement weather. Mainline valves must be capable of closure at all times. If it is impracticable to install a remote controlled valve, Keystone must submit a valve design and installation plan to the appropriate PHMSA Region Director(s), Central, Western, and Southwest Region to confirm the alternative approach provides an equivalent level of safety. For any valves that cannot be remotely actuated, Keystone must document on a yearly basis, not to exceed fifteen (15) months that personnel response time to these valves will not take over one hour.

33) Pipeline Inspection: The entire Keystone XL pipeline (not including pump stations and tank farms) must be capable of passing In-line Inspection (ILI) tools. Keystone shall prepare and implement a corrosion mitigation and integrity management plan for segments that do not allow the passage of an ILI device.

34) Internal Corrosion: Keystone shall limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA in the annual report. Keystone shall also report upset conditions causing BS&W level excursions above the limit.

a) Keystone must run cleaning pigs twice in the first year and as necessary in succeeding years based on the analysis of oil constituents, liquid test results, weight loss coupons located in areas with the greatest internal corrosion threat and other internal corrosion threats. At a minimum in the succeeding years following the first year Keystone must run cleaning pigs once a year, with intervals not to exceed 15 months.

b) Liquids collected during cleaning pig runs, such as BS&W, must be sampled, analyzed and internal corrosion mitigation plans developed based upon lab test results.

c) Keystone shall review the program at least quarterly based upon the crude oil quality and implement adjustments to monitor for, and mitigate the presence of, deleterious crude oil stream constituents.

35) Cathodic Protection: The initial CP system must be operational within six (6) months of placing a pipeline segment in service.

36) Interference Current Surveys: Keystone must perform interference surveys over the entire Keystone XL pipeline within six months of placing the pipeline in service to ensure compliance with applicable NACE International Recommended Practices 0169 (2002 or the latest version incorporated by reference in § 195.3) and 0177 (2007 or the latest version referenced through the appropriate NACE standard incorporated by reference in 49 CFR § 195.3) (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone shall determine if there have been any adverse effects on the pipeline and mitigate such effects as necessary. Keystone shall report the results of any finding of adverse effects and the associated mitigative efforts to the applicable Director(s), PHMSA Central, Western, and Southwest Regions within 60 days of the finding.

37) Corrosion Surveys: Keystone must complete corrosion surveys within six (6) months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey shall also address the proper number and

location of CP test stations as well as alternating current (AC) interference mitigation and AC grounding programs per NACE RP 0177. At least one (1) CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile. If placement of a test station is not practical within an HCA, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within six (6) months. Remedial actions must include a CIS on each side of the affected test station to the next test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

38) Initial Close Interval Survey (CIS): A CIS must be performed on the pipeline within one year of the pipeline in-service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed. Keystone must remediate any anomalies indicated by the CIS data including improvements to CP systems and coating remediation within six (6) months of completing the CIS surveys. CIS along the pipeline must be conducted with current interrupted to confirm voltage drops in association with periodic ILI assessments under 49 CFR § 195.452(j)(3).

39) Coating Condition Survey: Keystone must perform a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey within six (6) months after operation to verify the pipeline coating conditions and to remediate any integrity issues. Keystone must remediate any damaged coating indications found during these assessments that are classified as minor (i.e. 35% IR and above for DCVG or 50 dBμV and above for ACVG), moderate or severe based on NACE International Recommended Practice 0502-2002 (NACE RP 0502-2002) Pipeline External Corrosion Direct Assessment Methodology, or the latest version incorporated by reference in § 195.3. A minimum of two (2) coating survey assessment classifications must be excavated, classified and/or remediated per each survey crew and pump station discharge section.

40) Pipeline Markers: Keystone must install and maintain line-of-sight markings on the

pipeline except in agricultural areas or large water crossings such as lakes where line of sight signage is not practical. The marking of pipelines may also be subject to environmental permits and local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than forty-eight (48) inches. Keystone must replace removed or damaged line-of-sight markers, during pipeline patrols and maintenance on the right-of-way. Keystone, at a minimum, must identify and replace any missing or damaged line-of-sight markers during pipeline patrols (Condition 41). If pipeline patrolling for Condition 41 is performed via aerial patrolling and cannot consistently identify areas with missing or damaged line-of-sight markers, then Keystone must on a calendar year basis, not to exceed fifteen (15) months, conduct ground patrols.

41) Pipeline Patrolling: Patrol the right-of-way at intervals not exceeding three (3) weeks, but at least twenty-Six (26) times each calendar year, to inspect for excavation activities, ground movement, unstable soil, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline.

42) Initial ILI: Within three (3) years of placing a pipeline segment in service, Keystone must perform a baseline ILI using a high-resolution Magnetic Flux Leakage (MFL) tool. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline but no later than six (6) months after placing the pipeline in service.

43) Deformation Tool: Keystone must run a deformation tool through all mainline piping prior to putting the product in the pipeline and remediate all expanded pipe in accordance with PHMSA's "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Liquid Pipeline" dated October 6, 2009 or any subsequent PHMSA update to this guideline.

44) Future ILI: Future ILI inspection must be performed on the entire pipeline on a frequency consistent with 49 CFR § 195.452(j)(3) assessment intervals or on a frequency determined by fatigue studies of actual operating conditions.

a) Conduct periodic close interval surveys (CIS) along the entire pipeline with current interrupted to confirm voltage drops in association with periodic ILI assessments under § 195.452(j)(3).
b) CIS must be conducted within three (3) months of running ILI surveys when using a five (5) year ILI frequency, not to exceed sixty-eight (68) months, in accordance with 49 CFR § 195.452 (j) (3) assessment intervals.
c) CIS findings must be integrated into ILI Tool findings.

45) Verification of Reassessment Interval: Keystone must submit a new fatigue analysis to validate the pipeline reassessment interval annually for the first five (5) years after placing the pipeline into service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data. The fatigue analysis must be submitted to the appropriate PHMSA Director(s) in Central, Western, and Southwest Regions.

46) Flaw Growth Assessment: Two (2) years after the pipeline in-service date, Keystone shall use all data gathered on pipeline section experiencing the most severe historical pressure cycling conditions to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study shall be performed by an independent party agreed to upon by Keystone and PHMSA. Furthermore, Keystone shall share this study with PHMSA and the appropriate Director(s), PHMSA Central, Western, and Southwest Regions within sixty (60) days of its completion, and before baseline assessment is begun. These findings shall determine if an ultrasonic crack detection tool must be launched in that pipeline section to confirm crack growth. The study must also define when follow-up review and analysis will occur, not to exceed five (5) years, or sooner as determined by the study.

47) Direct Assessment Plan: Headers, mainline valve bypasses and other sections that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria.

48) Damage Prevention Program: Keystone must incorporate the Common Ground Alliance's damage prevention best practices applicable to pipelines into its damage prevention program.

49) Anomaly Evaluation and Repair: Anomaly evaluations and repairs must be performed based upon the following:

a) Immediate Repair Conditions: Follow 49 CFR § 195.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) ≤ 1.16 for anomaly repairs;

b) 60-Day Conditions: Follow 49 CFR §195.452(h)(4)(ii) except designate a FPR ≤ 1.25 for anomaly repairs;

c) 180-Day Conditions: Follow 49 CFR §195.452(h)(4)(iii) with exceptions for the following conditions which must be scheduled for repair within 180 days:

(1) Calculated FPR = < 1.39;

(2) Areas of corrosion with predicted metal loss greater than 40%;

(3) Predicted metal loss is greater than 40% of nominal wall that is located at a crossing of another pipeline; and

(4) Gouge or groove greater than 8% of nominal wall.

d) Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval.

e) Anomaly Assessment Methods: Keystone must confirm the remaining strength (R-STRENG) effective area method, R-STRENG - 0.85dL, and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. Keystone must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters.

f) Flow Stress: Remaining strength calculations for X-80 pipe must use a flow stress equal to the average of the ultimate (tensile) strength and SMYS.

g) Dents: For initial construction and the initial geometry tool run, Keystone must remove any dent with a depth greater than two percent (2%) of the nominal pipe diameter unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. For the purposes of this condition, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe wall thickness. The depth of the dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.

IV. Reporting, Records Retention, and Senior Level Certification Requirements

50) Reporting - Immediate: Keystone must provide immediate notification of all reportable incidents in accordance with 49 CFR Part 195, and shall notify the appropriate PHMSA regional office within twenty-four (24) hours of any non-reportable leaks occurring on the pipeline.

51) Reporting – 180 Day: Within 180 days of the pipeline in-service date, Keystone shall report on its compliance with all of these conditions to the PHMSA Associate Administrator and the appropriate PHMSA Directors in Central, Western, and Southwest Regions.

52) Annual Reporting: Keystone must annually report by February 15th each year the following to the PHMSA Associate Administrator and the appropriate Directors, PHMSA Central, Western, and Southwest Regions:

a) The results of any ILI run or direct assessment results performed on the pipeline during the previous year;

b) The results of all internal corrosion management programs including the results of:

(1) BS&W analyses

(2) Report of plant upset conditions where elevated levels of BS&W are introduced into the pipeline

(3) Corrosion inhibitor and biocide injection

(4) Internal cleaning program

(5) Wall loss coupon tests

c) Any new integrity threats identified during the previous year;

d) Any encroachment in the right-of-way, including the number of new residences or public gathering areas;

e) Any HCA changes during the previous year;

f) Any reportable incidents that occurred during the previous year;

g) Any leaks on the pipeline that occurred during the previous year;

h) A list of all repairs on the pipeline made during the previous year;

i) On-going damage prevention initiatives on the pipeline and an evaluation of their success or failure;

j) Any changes in procedures used to assess and monitor the pipeline; and

k) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

53) Threat Identification and Evaluation: Keystone must develop a threat matrix consistent with 49 CFR § 195.452 to accomplish the following:

a) Identify and compare any increased risks of operating the pipeline; and

b) Describe and implement procedures used to mitigate the risk.

c) Where geotechnical threats exist that may impact operational safety, Keystone must run a geospatial tool and assess procedures to implement for conducting mitigative measures along the affected pipeline.

54) Right-of-Way Management Plan: Keystone must develop and implement a right-of-way management plan to protect the Keystone pipeline from damage due to excavation, third party and other activities. In any areas where increased activities or natural forces could lead to increased threats to the pipeline beyond the initial threat conditions, the management plan must include increased inspections. The management plan must also include right-of-way inspection activities to complement the following:

a) Depth of Cover (Condition 19);

b) Pipeline Markers (Condition 40);

c) Pipeline Patrolling (Condition 41) ;

d) Damage Prevention Program (Condition 48); and

e) Threat Identification and Evaluation (Condition 53)

The Right-of-Way Management Plan and all of the above listed right-of-way inspection activities, Conditions 19, 40, 41, 48, and 53, must be reviewed for effectiveness and procedures updated as required on a periodic basis as conditions change, but not longer than once per calendar year not to exceed 15 months.

55) Records: Keystone must maintain all records demonstrating compliance with all conditions herein for the useful life of the pipeline.

56) Certification: A senior executive officer of Keystone must certify in writing the following:

a) That Keystone has met all of the conditions described herein;

b) That the written design, construction, and operating and maintenance (O&M) plans and procedures for the Keystone pipeline have been updated to include all additional requirements herein;

c) That Keystone has reviewed and modified its damage prevention program relative to the Keystone pipeline to include any additional elements required herein.

Keystone must send a copy of the certification with the required senior executive signature and date of signature to the PHMSA Associate Administrator and the Directors, PHMSA Central, Western, and Southwest Regions at least 90 days prior to operating the Keystone pipeline.

57) Within one (1) year of the in-service date, Keystone shall provide a detailed technical briefing, in person, to the appropriate PHMSA Directors in Central, Western, and Southwest Regions. The briefing shall cover the implementation of the requirements of all conditions herein, including all information required by Condition 52. On the basis of

PHMSA's review of the Condition 52 Annual Report and any additional information provided at the briefing, PHMSA may require additional information.