VIA ELECTRONIC MAIL TO: Burrough, Robert (PHMSA) robert.burrough@dot.gov

July 31, 2025

Mr. Robert Burrough
Director, Eastern Region
Pipeline and Hazardous Materials Safety Administration
840 Bear Tavern Road, Suite 300
West Trenton, NJ 08628

Re: Notice of Amendment CPF 1-2025-026-NOA Response

Dear Mr. Burrough:

As per instructions communicated in the PHMSA pipeline enforcement guidance document titled "Response Options for Pipeline Operators & Excavators in Enforcement Proceedings," section II a, the conclusions reached during the February 22 through July 24, 2024, inspection of Douglas Pipeline Company's ("Company," or "DPC,") procedures for the pipeline facilities in Shawville, Pennsylvania will not be contested, and the amended procedures are included below.

The following apparent inadequacies described below are from the letter to Mr. Ryan Estabrook, on July 1, 2025, from Mr. Robert Burrough, Director, Eastern Region, Pipeline and Hazardous Materials Safety Administration. As requested in the above letter, Reference number **CPF 1-2025-026-NOA**, we expect the "safety improvement costs…" to be a negligible amount.

Item #1:

Reference 192.605(a) Procedural manual for operations, maintenance, and emergencies.

PHMSA proposal for amendment: PHMSA proposes that DPC must revise its procedures to include adequate instructions for performing the annual review of its manuals of written procedures pursuant to section 192.605(a), including specifying the roles and responsibilities of DPC personnel who perform these reviews.

Douglas Pipeline Company Response

Douglas Pipeline Company has updated its procedure for performing the annual review of its manuals of written procedures as follows:

Operations and Maintenance Manual for the Penn Production Group Shawville Power Plant Version 4.1 effective 08/01/2025

Section 1
Operations and Maintenance Manual: Annual Review

The Operations and Maintenance Manual is to be reviewed once per calendar year at intervals not exceeding 15 months.

The review must be completed and documented by Douglas Pipeline Company's Director of Regulatory Compliance, or Integrity Management Specialist. The inclusion of any additional Douglas Pipeline personnel, pipeline owner personal, or subject matter experts (SME) shall also be documented.

The procedures in this manual shall be reviewed to ensure:
- Alignment with current operating conditions and appurtenances of the pipeline.
    - Changes to operating conditions or appurtenances discovered during the review period will be documented within the O&M manual, and a summary of the change will be included in the "Revision Description" column of the annual review record.

- Compliance with State and Federal pipeline safety regulations.
    - Changes to State and Federal pipeline safety regulations will be documented within the O&M Manual and a summary of the change will be included in the "Revision Description" column of the annual review record.

- Alignment with current versions of Douglas Pipeline Company's Standard Operating Procedures (SOP).
    - Changes to Douglas Pipeline Company's SOP's will be updated in this manual and a summary of the change will be included in the "Revision Description" column of the annual review record.

The Manual review shall be documented on the record below. The record includes:
- Date of the review.
- New version number as assigned upon review.
- Section number of revisions made during the review.

- Description of revisions made during the review.
- Name of personnel who completed the review.

In the event of operational, procedural, or regulatory updates that may occur between annual review periods, a revision number will be assigned and documented in the O&M Manual Review Record in section 1.1 of this manual.

49 CFR Part 192.605(a)
General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

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Item #2:

Reference 192.605(b)(1) Procedural manual for operations, maintenance, and emergencies.

DPC's O&M Manual failed to detail the steps that must be taken to prevent accidental ignition where gas presents a hazard of fire or explosion pursuant to section 192.751.

Douglas Pipeline Company Response

Douglas Pipeline Company has updated its procedure for Prevention of Accidental Ignition as follows:

Operations and Maintenance Manual for the Penn Production Group Shawville Power Plant Version 4.1 effective 08/01/2025

Section 5

49 CFR Part 192.751 Prevention of Accidental Ignition

Douglas Pipeline Company shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

Douglas Pipeline Company Employee Responsibilities

1. It is the responsibility of all employees of Douglas Pipeline Company to recognize the potential hazard posed by a leak of natural gas and the means and processes to prevent accidental ignition.

2. Douglas Pipeline field personnel responsible for completing the Job Safety Analysis form (https://douglasonline/JSA_2024.pdf) on the Appenate app prior to performing operations and maintenance tasks at the Shawville site to identify potential hazards and document preventative measures applied.

3. To ensure combustible vapors are not present in any area or structure, test the atmosphere using a combustible gas indicator (CGI). The entire area must be tested including false ceiling areas and any other area that may be hidden or closed to normal access

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Personal single or multi-gas monitors (MX4) will be properly worn by every employee of or worker supervised by employees of Douglas Pipeline Company including contractors, in work areas where there is a potential for exposure to or the collection of hazardous gases, such as yet not limited to Hydrogen Sulfide, Methane/Natural Gas Condensate, and/or the potential for flammable or combustible gases.

- All monitors will be bump-tested according to the manufacturer's instructions to ensure the monitor and the alarms are working correctly. The bump testing will be documented.

- All monitors will be calibrated per the manufacturers' instructions and have a sticker on the monitor indicating the most recent calibration.

- When the potential for Methane/Natural Gas Condensate is present is the work area, monitors will be used to constantly check the LEL of the air in the immediate work area to ensure that the LEL remains below 10% LEL.

- When the alarm is activated, (the LEL is at or above 10%), all work immediately ceases, and all workers will evacuate the work area. Actions will be taken to determine the reason for the alarm and then actions will be taken to remove the Methane/Natural Gas Condensate vapors from the area to below 10% LEL. These actions will be documented, and the Supervisor will be notified prior to the work being started up after the alarm.

- The monitors and alarms are to be checked daily including the batteries and calibrated/tested daily.

Prevention of Ignition Sources

Natural gas alone is not explosive, but when mixed with air in a 5 to 15 percent concentration it can ignite or explode. Every precaution should be taken to prevent unintentional ignition of natural gas when the presence of vapors may create a hazard of fire or explosion.

1. Do not cut by any method, pipe containing natural gas. All pipe used in natural gas service should be purged and free of a combustible mixture before cutting.

2. Welding or fires will be permitted only after the supervisor and/or welder has determined it is safe when in or near a hazardous area.

3. Internal combustion engines, whether fueled by gasoline, diesel, propane, natural gas, or other fuels, can act as ignition sources. Examples include:
    - Stationary engines such as compressors, generators, and pumps.
    - Mobile equipment or transports such as vans, trucks, forklifts, cranes, well servicing equipment, drilling rigs, excavators, portable generators, and welding trucks.
    - Contractor vehicles and motorized equipment.
    - Emergency response vehicles such as fire engines and ambulances.

- Vehicle-mounted engines on vacuum trucks, tanker trucks and waste haulers.
- Small portable engines such as mowers, blowers, generators, compressors, welders and pumps. This includes hand tools unrelated to a process, such as chain saws, brought in by contractors.

4. Smoking is prohibited. Do not carry matches, cigarette lighters, welding torch lighters, or other mechanical sources of ignition within 50 feet of any pressurized natural gas piping. Additionally, “no smoking” signs shall be posted as a reminder to all persons and non-operator qualified persons who may be in the vicinity of gated or fenced areas.

5. Approaching ignition sources when clothing is contaminated with oil or other flammables is to be avoided.

6. Electrical Arcing:
   a. Both Alternating Current (AC) and Direct Current (DC) systems can create an electric arc and cause an explosion in a hazardous atmosphere.
   b. Natural gas facilities usually contain complex grounding systems to provide protection for both “Touch” and “Arc” protection from high electric voltages. These systems are normally part of the design and are to be maintained in good working order to prevent electric arcing.
   c. This “Bonding” of sections of pipe and equipment, providing a path to ground is a necessary part of electrical safety and prevention on electrical arcs. These “Bonds” shall be always maintained. During maintenance, temporary bonds may need to be installed to maintain this path to ground.
   d. Portable equipment, both battery and alternating current equipment can produce electrical arcs that are an ignition hazard. No electrical equipment shall be operated in a hazardous atmosphere unless it is specifically rated for such use.
   e. Plastic Piping is a special case when dealing with potential explosive atmospheres. Plastic pipe will build a static charge on the inside and outside of the plastic pipe and at a high enough voltage will discharge causing an electrical arc. Venting gas from a plastic pipe shall not be allowed unless there are no means to prevent such an event. In this case, wet rags shall be wrapped around the venting area to provide an electrical path to the ground. Additionally, all tools in the area shall be grounded with a ground strap.
   f. Any tools necessary for work in a hazardous environment shall be not sparking brass tools.

Isolating Pipeline Segments for Planned Repair Work to Minimize the Potential of Ignition

1. General

Planned repair work on gas facilities should incorporate procedures to shut off or minimize the escape of gas. No portion of a pipeline should be cut out under pressure, unless the flow of gas is shut off or minimized by the use of line valves, line plugging equipment, bags, stoppers, or pipe squeezers. Where 100% shutoff is not feasible, a procedure shall be written with consideration of the following recommended precautions:

a. Plan the job to minimize the escape of gas and sequence steps to limit the time and amount of gas to which personnel are exposed.

b. Ensure that the size and position of the cut allows the gas to vent properly even with an employee in the excavation.

c. Protect personnel working in a gaseous atmosphere under an overhang, in a trench, or in a manhole.

2. Isolating pipeline segments

a. Preliminary action. The operator should conduct a prework meeting(s) to review the following with the personnel involved.

- The method of isolation.
- The purpose of each activity.
- Drawings, procedures, and schematics, as applicable.
- Responsibilities of each individual, including the designation of an individual to be in charge of the operation.

b. Isolation precautions.

- The operator should ensure that the isolation equipment is appropriate and sized correctly for the job.
- Isolation equipment left unattended should have a positive means of preventing unauthorized operation.
- Positive means should be provided at the work site to alert and protect personnel from unintentional pressuring. Consideration should be given to the use or installation of items such as:
  - Relief valves.
  - Rupture discs.
  - Pressure gauges.
  - Pressure recorders.
  - Vents.
  - Pressure alerting devices.
  - Other pressure detecting devices.

- Isolation equipment should be inspected and maintained prior to use.
- Temporary closures capable of withstanding full line pressure should have a means to determine pressure buildup, such as gauges and vents.
- Consideration should be given to the following to prevent the uncontrolled release of liquid hydrocarbons when cutting pipelines that might contain significant quantities of these liquids.
  - The elevation difference between the blowdown *valve* and cut location.
  - The impact of water displacement on liquid hydrocarbons in those instances where water may enter into the pipeline segment.

c. Monitoring isolated segments.

- Monitoring procedures should be established based on the pressure, volumes, closures, and other pertinent factors.
- Personnel assigned to operate isolation equipment should have a means to determine pressure buildups, such as gauges and vents.

- Personnel monitoring at remote locations should have communication with the work site and the individual in charge of the operation.

Notifications Prior to Purge or Blowdown

Public officials:
Local public officials should be notified prior to a purge or blowdown in those situations where the normal traffic flow through the area might be disturbed, or where it is anticipated that there will be calls from the public regarding the purge or blowdown.

Public in vicinity of gas discharge:
The public in the vicinity of the gas discharge should be notified prior to a purge or blowdown, if it is anticipated that the public might be affected by the process. The primary considerations for determining the need for notification are noise, odor, and the possibility of accidental ignition.

Item #3:

Reference 192.605(b)(1) Procedural manual for operations, maintenance, and emergencies.

DPC's O&M Manual failed to provide adequate instructions for determining the maximum allowable operating pressure for a pipeline (MAOP) segment in accordance with section 192.619.

Douglas Pipeline Company Response

Douglas Pipeline Company has updated its procedure for determining MAOP as follows:

Operations and Maintenance Manual for the Penn Production Group Shawville Power Plant Version 4.1 effective 08/01/2025

Section 7 MAOP, UPRATING

The MAOP of the Shawville pipeline is 1180-psi. If the pipeline exceeds its MAOP, it shall be shut down and an investigation will ensue. Pressure test documentation is on file.

7.1 MAOP: 49 CFR 192.619

The MAOP of the Shawville pipeline was established by hydrostatic pressure tests as performed in 2012 by the previous operator of the pipeline. Per records established by the previous operator, the pipeline was hydrostatically tested, and the Class Location 2 factor of 1.25 was used to establish the MAOP at 1180-psi.

In the event that PPG will add on to, or change their existing pipeline facility, or construct a new pipeline system, DPC will engage the services of an engineer to establish pipeline materials and MAOP requirements in accordance with the regulations of 49 CFR 192 and the standards incorporated within. Specific procedures for establishing design pressure, MAOP, and testing procedures will be added to this O&M manual.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined by the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors,[1,2] segment -		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under §192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For *offshore* pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

[2] For a component with a design pressure established in accordance with § 192.153(a) or (b) installed after July 14, 2004, the factor is 1.3.

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Item #4:

Reference 192.605(b)(2) Procedural manual for operations, maintenance, and emergencies.

Specifically, DPC's O&M processes for internal corrosion control were inadequate pursuant to the requirements of sections 192.475 and 192.477.

Douglas Pipeline Company Response

Douglas Pipeline Company has updated its procedure for internal corrosion control, and monitoring internal corrosion as follows:

Operations and Maintenance Manual for the Penn Production Group Shawville Power Plant Version 4.1 effective 08/01/2025

Section 8.12 Internal Corrosion Control: General 192.475

Eastern Gas Transmission and Storage Gas supplies interstate transmission quality gas to the PPG pipeline.
PPG-owned gas gathering pipelines also supply gas to the pipeline from their traditional well pads. On-pad processing of well gas includes a glycol-based dehydration process. Additionally, at the Shawville Power Plant metering and regulation station, pipeline gas quality is measured by an ABB Chromatograph. To date there have been no indications of corrosive constituents in the gas being transported through the Shawville transmission pipeline.

Per Douglas Pipeline Company SOP-40A:
1. Whenever a segment of gas pipe is removed or otherwise taken out of service, the internal surfaces should be examined for evidence of internal corrosion.
2. Indications of internal corrosion require a thorough investigation of adjacent pipe, both longitudinally and circumferentially, in order to discover the actual extent of internal corrosion.
   - Visually inspect for pitting
   - Visually inspect for erosion from liquids
   - Visually inspect for scale
   - Visually inspect for thinning
   - Visually inspect internal coating, if applicable

If corrosion is suspected, the services of an internal corrosion professional (NACE/AMPP certified) shall be engaged to determine the extent of corrosion and a mitigation plan.

O&M Section 8.14 Internal Corrosion Control: Monitoring 192.477

Eastern Gas Transmission and Storage Gas supplies interstate transmission quality gas to the PPG pipeline.
PPG-owned gas gathering pipelines also supply gas to the pipeline from their traditional well pads. On-pad processing of well gas includes a glycol-based dehydration process. Additionally, at the Shawville Power Plant metering and regulation station, pipeline gas quality is measured by an ABB Chromatograph. To date there have been no indications of corrosive constituents in the gas being transported through the Shawville transmission pipeline.

DPC SOP-40- Gas Sampling for Internal Corrosion Monitoring shall be performed at the gathering pipeline entry points to the Shawville transmission pipeline at least two times per calendar year at intervals not exceeding 7-1/2 months.

Discussion of Gas Sampling and Internal Corrosion

1. High Carbon Steel pipes are susceptible to external corrosion of which the industry uses coating and Cathodic Protection to minimize corrosion and thus safety and lifespan of the pipe.
2. Additionally, internal corrosion of the steel comprising the pipe can also occur and is also of concern.
3. One major advantage of corrosion control of the internal surfaces on a pipeline vs. the external surfaces is that the contents of the pipeline are completely at the control of the pipeline operations and maintenance services.
4. Operation of all pipeline valves may only be accomplished by Operator Qualified individuals wearing correct personal protective equipment and understand the operational characteristics of the system controlled by the valve (s) they are operating.
5. Internal corrosion will usually not occur in a pipeline unless there is an electrolyte available to form the corrosion cell. Glycols from the dehydration equipment and especially water must not be allowed to enter the pipeline to the maximum extent possible. Other contaminants which may occur during gas extraction such as Hydrogen Sulfide will combine with water to for acids and will lead to accelerated corrosion of internal surfaces.
6. It is for these reasons that when gas is supplied to Douglas Pipeline Company's maintained pipeline systems, sampling for moisture and hydrogen sulfide will be performed periodically (two times per calendar year NTE 7-1/2 months) to ensure that water and hydrogen sulfide are maintained below acceptable levels or as low as possible.
7. Maximum levels of moisture in pipeline gas via sampling shall be <7#/mmscf and maximum levels of Hydrogen Sulfide shall be <.25 grains per 100 ft3 or 4 ppm.

Sampling Methods

1. Sampling of natural gas streams flowing into Douglas Pipeline assets shall be performed at each input stream post processing of the gas and prior to injection into the pipeline.
2. The two most common means of sampling natural gas constituents involve using sample "Bombs" and point sample using chemical analysis "colorimetric" or stain tubes. Sample bombs are collected in stainless steel cylinders and transported to laboratory for analysis and the colorimetric tubes are read in the field.

3. Regardless of the method used for sampling and analysis for moisture and hydrogen sulfide in natural gas, laboratory and colorimetric gas tube manufacturer's recommendation for the sampling and analysis of the results must be followed for accurate results. Please refer to the manufactures/laboratory specific procedures and protocols.
4. During the sampling process, purging of the short sampling section of the pipeline and sampling apparatus must be performed. This will result in the release of flammable gas and all appropriate precautions and PPE shall be considered and used.
5. Prevention of ignition protocols and personal gas monitoring shall be used while purging and sampling is ongoing.

Sampling Process

1. Identify all necessary sample points that supply production gas to the Douglas Pipeline asset.
    a. Ensure that the sample points are downstream of all processing and prior to pipeline injection.
    b. Ensure that each sample point has the appropriate connection for sample collection along with proper isolation methods for controlling as flow.
    c. Install collection/sampling apparatus, ensure there are no ignition dangers, ensure personal gas monitoring device is on your person and function properly, then begin purging gas at the appropriate rates in preparation for sampling.
    d. If using stainless steel "Bombs", perform the purging and capture of the gas sample as per laboratory procedures.
    e. If using colorimetric sample tubes, perform the analysis as per manufacturer's instructions.
    f. Record results and or sampling/chain of custody report.
    g. Normalize system where the sample was taken.
    h. Continue sampling from all injection points using a – g above.

2. Each system where gas sampling is taken must have an appropriate record of the samples taken. A form is provided on SOP-40. Minimum information is included in this form. The form may be customized, and appropriate information added for each system where Douglas Pipeline performs gas sampling.
    a. All gas sampling sheets and results if electronically recorded must be kept in the Douglas Pipeline Egnyte system for the life of the pipeline.
    b. Results should be compared over time to determine if any trends are occurring in gas quality.
3. Samples from potential sources of pipeline contamination must be sampled quarterly when flowing gas into Douglas Pipeline Company operated systems.

If it is discovered that corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7-1⁄2 months.

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<u>Item #5:</u>

Reference 192.605(b)(8) Procedural manual for operations, maintenance, and emergencies.

Specifically, DPC's O&M Manual failed to reference the documentation supporting the procedural effectiveness review and failed to define the frequency for performing the periodic effectiveness review.

Douglas Pipeline Company Response

Douglas Pipeline Company has included its entire procedure SOP-62 for Procedure Effectiveness Review as follows:

Operations and Maintenance Manual for the Penn Production Group Shawville Power Plant Version 4.1 effective 08/01/2025

Section 9.2

Periodic Pipeline Procedure Effectiveness Review §192.605(b)(8)

The effectiveness and adequacy of procedures used in normal operations and maintenance, and by DPC's contractors, will be reviewed periodically by Douglas Pipeline technicians and supervisors.

- The review will take place in the field where the procedures are performed during a routine pipeline patrol.
- These reviews could occur on site at any of the pipeline systems operated by DPC- the location of the review is not limited to this site only.
- Procedures will be modified should any deficiencies be found.

Records of these reviews are kept in the Task Procedure Review folder in DPC's online compliance library.

Douglas Pipeline Company SOP-62: Procedure Effectiveness Review:

Regulatory Requirement 49 CFR 192.605(b)(8):	Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found. Douglas Pipeline shall periodically review the work done by their Operator Qualified personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance. Any deficiencies found while performing the procedures shall be documented, and the procedures shall be amended accordingly.

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Applicability	All regulated natural/landfill gas pipelines
Frequency	Periodically – At least one task review per year. Also as needed in the event of an AOC, accident, or incident.
Revision Date/Number	11/19/2015 – Version 1 Current review date: 05/09/2025

Evaluation Process:	Complete the following evaluation of tasks as performed by Douglas Pipeline Operator Qualified Technicians that: 1) are performed on a pipeline facility 2) are operations or maintenance tasks 3) are performed as a requirement of 49 CFR Part 192 4) affects the operation or integrity of the pipeline
Reasons for Evaluation: (Check all that apply)	
	Review of the effectiveness and adequacy of the procedures being performed by OQd technicians
	Observe performance on the job or in simulations to determine the technician performing the task is qualified
	Evaluation to determine if the technician's performance of a covered task contributed to an incident or accident as defined in 49 CFR Part 191
	Evaluation to determine if individual is no longer qualified to perform a covered task
	Record training required to ensure individual performing covered tasks have necessary knowledge and skills to perform tasks in a manner that ensures the safe operation of the pipeline facilities
	Other- please specify
Review Date	
Review Location	
Participating Technicians	
Evaluator Name	

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Name and Number of Procedure	
1) Perform the task according to Douglas Pipeline's written procedure.	
2) Evaluate the effectiveness of the written procedure:	
	Does the procedure include AOCs and pre-requisites?
	Does the procedure accomplish the specified task safely?
	Does the procedure accomplish the specified task so that the pipeline system operates as expected?
	Other
3) Evaluate the technician's performance of the procedure	
	Did the technician have proof of calibration of equipment used to perform the task?
	Did the technician check for AOCs prior to performing the task?
	Did the technician perform the task safely and according to the procedure?
	Other
How was the review conducted?	
Example: We followed the Douglas Pipeline written procedure with the proper tools.	
Recommended procedure improvements: Does the procedure as written accomplish the task effectively?	
Recommendations	
Recommended technician performance improvements:	
Complete a "Management of Change" form for any procedure updates resulting from this review	

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<u>Item #6:</u>

Reference 192.615 Emergency plans.

Specifically, DPC's Emergency Response Plan, V. 3 2023-24 (7/1/2023) (ERP) and its O&M Manual were inadequate as they did not provide sufficient detailed plan for DPC personnel to follow to investigate and identify a potential rupture.

Douglas Pipeline Company Response

Douglas Pipeline Company has updated its procedure for Notification and Identification of a potential rupture as follows:

Operations and Maintenance Manual for the Penn Production Group Shawville Power Plant Version 4.1 effective 08/01/2025
Section 12.2 Notification of Potential Rupture 192.635

And Douglas Pipeline Company Emergency Response Plan for the Penn Production Group Shawville Power Plant Version 4.0, effective 08/01/2025
Section 7 Notification of Potential Rupture 192.635

Rupture Indicators and Notification Sources
DPC may be alerted to a potential rupture from any of the following sources:

1) Visual or audible signs reported by DPC and/or other pipeline personnel in the field:
- Roaring or hissing sounds
- Unusual ground disturbance, dead vegetation, or vapor clouds
- Flames or smoke

2) Third parties who may have observed a line strike or other potential leak source, including:
- Emergency responders
- Members of the public
- Excavators or contractors
- Neighboring pipeline operators

3) Douglas Pipeline Company personnel observing an unexpected flow rate change at the upstream or downstream stations.

Flow Disparity Observation
- Gas flow is monitored digitally at the Eastern Gas Transmission & Storage pipeline tap and at the pipeline's downstream terminus at the inlet to the Shawville Power Plant meter station.
- Flow from Eastern is typically between 800-900-Psig.

When flow data is available:
- A large difference between incoming and outgoing flow may indicate unaccounted-for product loss.

- Flow comparison can be performed by field personnel on-site or via daily logs that are remotely transmitted to the Shawville power plant/viewable by DPC personnel.

  Note: Flow disparities may be used alongside pressure readings to reinforce rupture identification, but do not delay initial response waiting for perfect alignment.

Gauge pressure comparison

- A significant pressure loss at the delivery end, with stable or high pressure at the inlet, may indicate a downstream rupture.
- A sudden drop in pressure at both ends may indicate a major breach.

Field Verification and Immediate Decision-Making

If pressure readings and flow data suggest a loss of containment, or if substantiated by third-party reports, DPC personnel must treat the event as a rupture and immediately implement emergency procedures.

- Call 911 immediately.
- Notify DPC and PPG emergency response personnel.
- Activate the Emergency Response Plan.
- Notify Eastern Gas Transmission and PPG Gathering operations to shut off service.
- Isolate the affected segment using nearest mainline valves.
- Complete the Initial Emergency Notification Form (Section 5 of the Emergency Response Plan)
  - Time of initial indication
  - Source of alert (gauge, flow meter, third party)
  - Action taken
  - Timeline, etc.

When it is safe to do so, pipeline personnel will then patrol the right-of-way and pipeline appurtenances to determine the source of the pressure decrease and will notify operational personnel of the findings as soon as possible initially in person or by telephone.

Reporting Procedures

As needed, the Reporting Procedures in the Operations and Maintenance Manual will be executed by Douglas Pipeline operational staff.

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Item #7:

Reference 192.805 Qualification program.

Specifically, DPC's Natural Gas Pipeline Operator Qualification Program, V-14, (8/31/2023) (OQ Plan) failed to include adequate provision for granting exceptions to requalification requirements for individuals disqualified from a covered task due to prolonged periods of physical, mental, or medical impairments.

Douglas Pipeline Company Response

Douglas Pipeline Company has updated its procedure for its Operator Qualification – requalification requirements as follows:

Douglas Pipeline Company Operator Qualification Program- Version 13.1 Effective 08/01/2025

Section 3.8: Disqualification from Independent Task Performance, and Re-qualification Steps

Note: Disqualification because of a physical, mental, or medical impairment may be considered a temporary medical suspension that does not require remediation and re-qualification. When a physician has evaluated the medically disqualified individual, and cleared them for full duty, the individual will be automatically re-qualified as long at their qualifications are not out of date

We appreciate your staff's thorough review of our procedures and value the feedback we've received, as it supports our commitment to safe pipeline operations and continuous program improvement.

Sincerely,

Andrea Shacklett

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cc:
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Shawn Mason, Integrity Specialist Douglas Pipeline Company