U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

8701 S. Gessner, Suite 630
Houston TX 77074

NOTICE OF AMENDMENT

ELECTRONIC MAIL - RETURN RECEIPT REQUESTED

December 1, 2021

Matthew Ramsey
President & Chief Executive Officer
Energy Transfer Company
1300 Main Street
Houston, Texas 77002

CPF 4-2021-020-NOA

Dear Mr. Ramsey:

From May 10, 2021 through May 13, 2021, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code (U.S.C.), inspected Energy Transfer Company's (ETC) Integrity Management Plan (IMP) procedures for its gas facilities via video teleconference.

Based on the inspection, PHMSA identified the apparent inadequacies found within ETC's plans or procedures, as described below:

1. **§ 192.907 What must an operator do to implement this subpart?**
   (a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

§ 192.915 - What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

ETC's written IMP procedures are inadequate because they do not include a requirement that supervisory personnel must possess and maintain a thorough knowledge of the integrity management program procedures in accordance with §§ 192.907 and 192.915(a). Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, Section 11: Qualification and Training* (Revision Date: April 1, 2021) states: "The integrity management process must be executed, and the results reviewed by qualified personnel."

ETC must amend its procedures to include a requirement that supervisory personnel will maintain and possess a thorough knowledge of the integrity management program procedures in accordance with §§ 192.907 and 192.915(a).

2. **§ 192.907 What must an operator do to implement this subpart?**

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

§ 192.933 - What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(b) ***Discovery of condition.*** **Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.**

ETC's written IMP procedures are inadequate because they do not define or clarify the "Date of Discovery" in the context of pressure testing, which may involve re-tests and multiple discovery dates, in accordance with §§ 192.907 and 192.933.

Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, Section 7.1 Discovery of a Condition* (Revision Date: April 1, 2021) is inadequate because it does not explain that there may be several dates of discoveries, each for different findings. A condition can only be discovered once per finding/test, and a "Pass" is not necessarily a new date of discovery, especially when remediation is already occurring. There should only be one date of discovery for each finding or test, and then the subsequent remediation acceptance date. Additionally, regarding ILI Assessments and the "Date of Discovery," PHMSA noted during the inspection that ETC's procedures state that the "Date of Discovery" is equivalent to the data Acceptance Date after the ILI data has been received and loaded into the integrity database. However, the input of data into a database is not relevant to having adequate information and should not be a factor in determining "Date of Discovery."

ETC must revise its procedures to define/clarify the "Date of Discovery" in accordance with §§ 192.907 and 192.933(b).

3. § 192.907 What must an operator do to implement this subpart?

(a) ***General.*** **No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.**

§ 192.935 - What additional preventive and mitigative measures must an operator take?

> **(a)** ***General requirements.*** **An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, 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.**
> **(b) …**
> **(c)** ***Automatic shut-off valves (ASV) or Remote-control valves (RCV).*** **If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.**

ETC's written IMP procedures for Preventive and Mitigative Measures are inadequate because they permit ETC to review certain factors or refer to a 1995 Southwest Institute Study, when determining the need for installation of ASV or RCV as outlined in accordance with §§ 192.907 and 192.935.

Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021*(Revision Date: April 1, 2021), *Section 9.2: Mitigative Actions Determination Process*, states:

> In determining the need for installation of an ASV or RCV, the Operations Manager will review the following or refer to Southwest Institute Study:
> - The swiftness of leak detection and pipeline shutdown capabilities,
>   - System detection times
>   - Operator response times
>   - Remotely controlled valve response characteristics, and
>   - System isolation time, if applicable.
> - Location and capabilities of existing ASV or RCV,
> - ASV response to releases in transient conditions,
> - Potential effects of additional ASV on conducting proper valve sequencing during intended ASV activations,
> - Potential effects of additional ASV on personnel to promptly detect and react to inadvertent AS activations,

- Relevant operating modes beyond full flow conditions,
- Consideration of risk results,
- Rate of leakage,
- The volume that can be released,
- Potential for ignition,
- Proximity to power sources,
- Location of the nearest response personnel, and
- Benefits expected by reducing the release size.

Section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), requires that an operator must conduct, in accordance with one of the risk assessment approaches, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote-Control Valves. ETC's procedures provide the Operations Manager with the option of choosing to use current operational capabilities of the pipeline or a study that is twenty-six years old.

On July 30, 2021, ETC submitted a letter to PHMSA and included the 1995 Southwest Institute Study. The report states: "The findings of this report statistically show that it is unlikely that a ROV or ASV will mitigate the consequences of a pipeline failure. However, case-by-case reviews are performed in both HCA and Non-HCA segments to determine the addition of ASV or RSV would be useful in reducing response time or gas loss. Additionally, will perform a review on the Stingray Pipeline system to determine the adequacy of response time to the offshore platform from the onshore point."

ETC must revise its procedures to state that current operational capabilities will be utilized as required by § 192.935.

4. § 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

§ 192.937 - What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

ETC's written IMP procedures for performance of evaluations and continuous evaluation procedures are inadequate because they do not define or specify when the periodic evaluation will be conducted, as required by § 192.937(b).

Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 8 Continual Re-Evaluation & Reassessment* (Revision Date: April 1, 2021) and *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 8.2 Re-Evaluation* (Revision Date: April 1, 2021) states, "The Company will conduct a re-evaluation as frequently as necessary to assure the integrity of each covered segment." This does not contain enough specificity for the record keeping requirements of the "re-evaluation" and needs clarification as to what the minimum required frequency is to ensure that periodic re-evaluations do actually occur. Procedural language should require the meeting agenda and minutes/commentary as a part of the "official record." ETC should consider conducting the re-evaluation during the same interval as the risk assessment discussed in *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 5 Risk Assessment* (Revision Date: April 1, 2021) and *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 5.1 Risk Assessment Models* (Revision Date: April 1, 2021).

ETC must revise its procedures to define and specify when the periodic evaluation will be conducted in accordance with §§ 192.907 and 192.937.

5. § 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

§ 192.941 - What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with § 192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§ 192.919 and 192.921.
(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.
(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
(2) *Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must— (i) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and
(i) …
(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
(c) *Internal corrosion*. To address the threat of internal corrosion on a covered segment, an operator must—
(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)-(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

ETC's written IMP procedures for low stress assessments are inadequate because they do not include specific record keeping requirements for these assessments as required by § 192.941.

Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021* (Revision Date: April 1, 2021), *Section 8.5: Low Stress Reassessment* and *Appendix D-6 Low Stress Reassessment Plan* (Effective Date: March 1, 2016) should provide more specificity for the record keeping requirements of the 7-year "assessment." This includes, but is not limited to, what that record is to specifically include, what format, and guidelines for remedial actions, etc.

ETC must revise its procedures to include specific record keeping requirements for low stress assessments in accordance with §§ 192.907 and 192.941.

6. § 192.927 - What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) . . .
(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.
(1) …
(5) *Other requirements.* The ICDA plan must also include –
(i) …
(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience;

ETC's written procedures for Internal Corrosion Direct Assessment (ICDA) are inadequate because they do not contain provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that becomes less stringent as the operator gains experience in accordance with § 192.927(c)(5)(ii).

Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 7 Provisions for Remedial Action (Repair/Mitigation)* (Revision Date: April 1, 2021), *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 7.5 Internal Corrosion Direct Assessment (ICDA)* (Revision Date: April 1, 2021), and *Appendix D-2 Internal Corrosion Direct Assessment (ICDA) Plan* (Effective Date: March 1, 2016) do not contain provisions as required by § 192.927(c)(5)(ii). The ICDA plan does not document when the more restrictive criteria are applied when conducting ICDA for the first time on a covered segment.

These more restrictive criteria are for pre-assessment, indirect inspection, direct examination, and post assessment steps of the ICDA process. ETC needs to document for each specific assessment how the more restrictive criteria were applied.

ETC must revise the ICDA procedures to include provisions for applying more restrictive criteria in accordance with § 192.927(c)(5)(ii).

7. **§ 192.929 - What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?**

   (a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.
   (b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—
   (1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.
   (2) *Assessment method.* The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

ETC's written procedures for ICDA are inadequate because they do not clarify the SCC threat susceptibility criteria in accordance with § 192.929. Specifically, ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, Section 4: Identification of Threats* (Revision Date: April 1, 2021) and ETC's *Pipeline Integrity Management Plan, ETC GAS IMP_Rev013 04012021, 4.1.3 Stress Corrosion Cracking (SCC)* do not reflect the current industry SCC susceptibility criteria (SCC is a threat if the MAOP is > 60% SMYS and has a coating other than FBE). Section 4.1.3 defines the susceptibility criteria for high-pH SCC, including the stress factor, temperature, coating, and distance from a compressor station. ETC's current definition fails to account for the threat of near-neutral-pH SCC, which only has a stress factor and coating factor. This concern was discussed during the inspection and ETC stated that it currently has a procedural revision pending to differentiate between high-pH and near-neutral-pH SCC resulting from an incident on the Florida Gas system (this same recommendation was made by the Michigan Public Service Commission Staff in 2019 during the Panhandle Eastern Inspection and appears to have been unaddressed.

ETC must revise its procedures to clarify the SCC threat susceptibility criteria in accordance with § 192.929.

<u>Response to this Notice</u>
This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.206. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*.

Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document, you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Following the receipt of this Notice, you have 30 days to submit written comments, revised procedures, or a request for a hearing under § 190.211. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue an Order Directing Amendment. If your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.206). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

It is requested (not mandated) that Energy Transfer Company maintain documentation of the safety improvement costs associated with fulfilling this Notice of Amendment (preparation/revision of plans, procedures) and submit the total to Mary L. McDaniel, P.E., Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration.

In correspondence concerning this matter, please refer to **CPF 4-2021-020-NOA** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

MARY LOUISE MCDANIEL Digitally signed by MARY LOUISE MCDANIEL Date: 2021.12.01 13:35:29 -06'00'

Mary L. McDaniel, P.E.
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Enforcement Proceedings*

cc: Eric Amundsen, Sr. VP, Energy Transfer, eric.amundsen@energytransfer.com
Todd Nardozzi, Director Regulatory Compliance, Energy Transfer, todd.nardozzi@energytransfer.com