Leveraging Engineering Assessments and Engineering Critical Assessments for an Enhanced and Practical Approach to Evaluating Pipeline conditions

Cassandra Moody[1], Parth Iyer[2]

[1]Time for Change, LLC., [2]Dynamic Risk Assessment Systems

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Abstract

Engineering Critical Assessments (ECA) have been incorporated into United States pipeline safety regulations[1] as a means for reconfirming the Maximum Allowable Operating Pressure (MAOP) for onshore steel gas transmission pipelines, while Engineering Assessments (EA) have been a longstanding method for proving consistent conclusions and recommendations across a variety of situations in accordance with the Canadian standards and guidance in CSA Z662:19. The purpose of this paper is to discuss the similarities and differences in the approach of ECAs and EAs while offering practical considerations to improve the resulting assessments conducted. The findings of a recently conducted EA with a semi-quantitative risk assessment will be discussed as an example of how engineering principles and a threat perspective supplement the risk algorithm-generated results. The primarily fracture-mechanics basis of ECAs, similarly, can be enhanced when a broader threat perspective is applied. Practical considerations will be discussed with applications geared to responding to new regulations and utilizing sound engineering consideration for a variety of pipeline engineering assessments.

Introduction

Engineering Critical Assessments (ECA) have been incorporated into United States pipeline safety regulations[1] as a means for reconfirming the Maximum Allowable Operating Pressure (MAOP) for onshore steel gas transmission pipelines, while Engineering Assessments (EA) have been a longstanding method for proving consistent conclusions and recommendations across a variety of situations in accordance with the guidance in Canadian (CA) standard CSA Z662:19[2].

While both ECAs and EAs are established practices with their own minimum standards and regulatory requirements, they each follow different progressions to satisfy their respective applications. This paper outlines the key differences between the EA and ECA approaches and proposes a consolidated approach that is applicable to circumstances where EAs or ECAs may be employed.

1.1 Definitions

The terminology surrounding the analytical process compared in this paper varies across North American pipeline safety authorities. To clear up confusion, the usage of terms in this paper will identify their respective regulatory authorities.

[1] 49 Code of Federal Regulations (CFR) Part 192, § 192.632 Engineering Critical Assessment for MAOP Reconfirmation: Onshore steel transmission pipelines
[2] Canadian Standards Association (CSA) Z662: Oil and Gas Pipeline Systems, Eighth Edition, 2019

Both EA and ECA are defined terms in the Canadian Standard (CSA) Z662, adopted by the Canadian Energy Regulator Onshore Pipeline Regulations (SOR/99-294[3]). CSA distinguishes EA from ECA as described in Table 1.

[3] Canadian Energy Regulator Onshore Pipeline Regulations (SOR/99-294), 2022-09-27

CSA Z662[4]	**Engineering Assessment (EA)**	**Engineering Critical Assessment (ECA)**
Definition	*A documented assessment of the effect of relevant variables upon fitness for service or integrity of a pipeline system, using engineering principles, conducted by or under the direct supervision of a competent person with demonstrated understanding and experience in the application of engineering and risk management principles related to the issues being assessed.*	*An analytical procedure based on fracture mechanics principles that allow the determination of the maximum tolerable sizes for imperfections in fusion welds*
Use	EAs determine fitness-for-service in a variety of circumstances.	ECAs are conducted specifically for the consideration of imperfections in girth welds after construction. Guidance for the evaluation and acceptance of anomalies is provided in Annex J of the Standard.

Table 1 *: Canadian Standard Definitions*

The United States (US) pipeline safety federal regulations do not specifically define the term Engineering Assessment; however, Engineering Critical Assessment is defined in the natural gas transportation safety regulations in 49 CFR Part 192.3[5] and is referenced in Subpart L - Operations Sections 192.624[6] and 192.632[7].

Table 2: United States Regulatory Definition

US Regulations 49 CFR Part 192[8]	**Engineering Critical Assessment (ECA)**
Definition	*A documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, the operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.*
Use	ECAs are not specific to flaws in girth welds and have a broader fitness-for-service intent across various threat and defect types that overlaps with that of EAs in the Canadian Standard.

[4] CSA Z662: Oil and Gas Pipeline Systems, Eighth Edition, 2019
[5] 49 CFR Part 192.3: Definitions
[6] 49 CFR Part 192.624, MAOP reconfirmation: onshore steel gas transmission pipelines
[7] 49 CFR Part 192.632, ECA for MAOP Reconfirmation

***Table 3**: United States Regulatory Definition*

This addition to the existing pipeline safety regulations as part of RIN 2137-AE72 Final Rule[9], commonly referred to as the "Gas Mega Rule," the Pipeline Hazardous Materials Safety Administration (PHMSA) established new MAOP reconfirmation requirements through a choice of six methods. One of the specified methods is ECA analysis.

The related hazardous liquid pipeline safety regulations in 49 CFR Part 195[10] do not explicitly define EA or ECAs. However, engineering analysis as related to pipes susceptible to longitudinal seam failures is mentioned in 49 CFR Part 195.303(d)[11] as a risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines. This clause requires consideration of steel mechanical properties, including fracture toughness, similar to that of Canadian ECAs.

Figure 1 summarizes the convergencies in the four terms discussed above, related to the documented engineering procedures discussed above from the US and CA regulatory compliance perspective.

[9] Federal Register A Rule by PHMSA on 10/01/2019
[10] 49 CFR Part 195 - Transportation of Hazardous Liquids by Pipeline
[11] 49 CFR Part 195.303(d), Risk-based alternatives

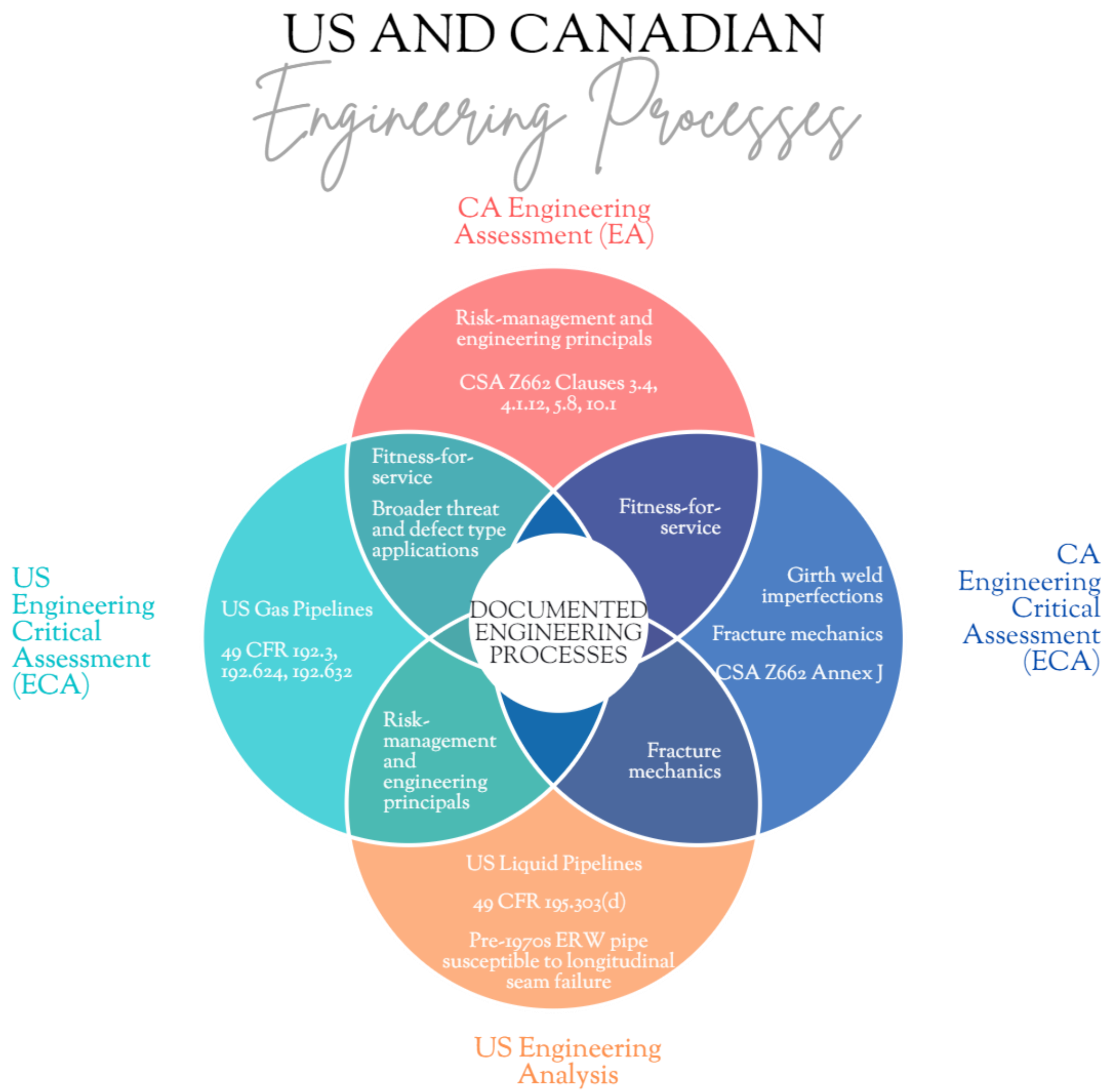

Figure 1: *Documented Engineering Processes in the US and CA*

In addition to the federal pipeline safety regulations the US and the standard incorporated by reference in CA, industry standards and guidance bodies have discussed engineering assessments in various documents to provide pipeline operators guidance for the safe operation of assets.

The American Petroleum Institute (API) maintains a robust standard detailing the Fitness-For-Service (FFS) methodology in API 579[12]. FFS Assessment[13] is defined as a methodology whereby flaws or a damage state in a component is evaluated to determine the adequacy of the component for continued operation. API 579 Part 2 details an eight-step procedure to determine the FFS of a component organized by flaw type and damage mechanism[14]. When fracture mechanics is considered, damage

[12] American Petroleum Institute (API) 579 Fitness for Service Standard, December 2021
[13] API 579 page 54 1A.32
[14] API 579 Flaw and Damage Assessment Procedures Table 2.1, page 76

mechanisms like brittle fracture, crack-like features, corrosion, and other damage, align with the CSA Z662 ECA principles.

The API 579 FFS assessment procedures cover both the present integrity of the component given a current state of damage and the projected remaining life. Qualitative and quantitative guidance for establishing remaining life and in-service margins for the continued operation of the equipment are provided in regard to future operating conditions and environmental compatibility.

Another standard API 1104[15], *Welding of Pipelines*, details analysis to determine weld-specific fitness-for-purpose criteria. The terms ECA and fitness-for-service are used interchangeably in this standard. Similar to Canadian ECAs, additional qualification tests, stress analysis, and inspection are essential under this standard.

The American Society of Mechanical Engineers standard B31.8S, M*anaging System Integrity of Gas Pipelines*[17], identifies ECA as suitable for threat prevention and repair method for certain instances of internal corrosion, external corrosion, stress corrosion cracking, girth weld defects, third-party damage, manufacturing, and construction threat disposition.

Beyond federal regulations and industry standards organizations, several organizations have mentioned EAs in their reports. Two notable industry reports include the International Natural Gas Association of America (INGAA) *Fatigue Considerations* report[18] and the Pipeline Research Council International (PRCI) report on *Fatigue Life Assessment of Dents*[19]. Both reports detail fracture mechanics-based calculations and assessments for flaws to determine the fitness for service using ECA principles.

1.2 Requirements and Considerations

In CA, the requirements for engineering assessments are provided in Clauses 3.4, 4.1.12, 5.8 and 10.1 of CSA Z662. Clause 3.4 establishes the structural requirements for the engineering assessment; Clause 4.1.12 outlines the considerations for pipeline design; Clause 5.8 outlines the considerations for material qualification, and Clause 10.1 provides the detailed elements that need consideration *as applicable*. It is noted that there is an opportunity to focus the EA *as applicable* to a specific threat or circumstance, but there is also a requirement to consider risk assessment as part of the analysis[20].

[15] API 1104 Welding of Pipelines, 22nd Edition, 2021, Annex A page 121
[17] American Society of Mechanical Engineers (ASME) B31.8S Managing System Integrity of Gas Pipelines, 2018, Table 7.1-1 page 35.
[18] INGAA Fatigue Considerations for Natural Gas Transmission Pipelines, June 30, 2016
[19] PRCI Fatigue Life Assessment of Dents with and without Interacting Features, PR-214-114500-R01, December 20, 2018
[20] "Engineering Assessments in Support of Pipeline Safety – Emerging Trends and Approaches," B. Mittelstadt; D. Williams, Pipeline Pigging and Integrity Management Conference, February 2022

In the US, Operators that chose to conduct an MAOP reconfirmation under 49 CFR Part 192.624(c)(3) "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment must assess: *Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of-way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline*[20].

Beyond evaluating the material properties, required for the US ECA analysis, the documented records of material properties considered in such an analysis to reconfirm the MAOP must be traceable, verifiable, and complete (TVC) records. If the records for material properties used in the ECA are not TVC, the operators of gas transmission pipelines in the US must then adhere to the verification testing stipulations in 49 CFR 192.607(a)[21]. Until documented material properties are available, the federal pipeline safety code stipulates gas transmission pipeline operators are to use conservative assumptions listed in for material toughness[22] and strength[23] values while conducting predicted failure pressure analysis reviews by a subject matter expert for corrosion metal loss and crack-like defects in accordance with 49 CFR 192.712.

Material Toughness (ft.-lbs)	**Material Strength (psi)**
Charpy V-Notch CVN) values from comparable pipe, or	Grade A pipe (30,000 psi), or
CVN values from the material property verification process, or	The SMYS value currently used as the basis for the current MAOP.
If the pipeline has no history of incidents caused by crack-like defects, use maximum CVN values of 13.0 ft.-lbs for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects, or	
If the pipeline has a history of incidents caused by crack-like defects, use maximum CVN values of 5.0 ft.-lbs for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects, or	
A conservative operator analyzed value, requiring advance PHMSA notification.	

Table 4: Conservative Assumption Values- Gas Transmission Operators

1.3 Applications

[21] 49 CFR 192.607 Verification of Pipeline Material Properties and Attributes: onshore steel gas transmission pipelines, Paragraph C.
[22] 49 CFR 192.712 (i) Material toughness assumptions for US gas transmission operators
[23] 49 CFR 192.712 (ii) Material strength assumptions for US gas transmission operators

In this paper, the general term *Engineering Assessment* (EA) will signify a documented process of analysis for a variety of pipeline integrity purposes. Specific regulatory requirements for a given asset must always be considered based on the jurisdiction of the individual asset and any applicable regulations.

To develop an EA methodology applicable to assets outside of a particular geographic location, the strengths and weaknesses of each method are considered in .

	ECA	EA
Strengths	• Emphasis on Fracture Mechanics to establish critical flaw sizes • Robust applicability to specific equipment, defects, and failure mechanics. • Provides an alternative method, based on engineering principles, using conservative assumptions to demonstrate safe operation.	• Comprehensive assessment of particular threat(s) to determine fitness for service • Requires the direct supervision of a competent person • Must consider risk assessment results • Can be employed when implementing regulatory code requirements are not feasible • Encourages conservative assumptions to be employed when evaluating threats with low data certainty or missing information
Weaknesses	• Rigorous data requirements in order to perform analysis • Multiple fracture mechanics models and fatigue crack growth methodologies, not incorporated by reference like corrosion metal loss in US code.	• No explicit requirement to consider fracture mechanics • No explicit requirement to consider the effect of prevention and mitigation systems

Table 5: *Strengths and Weaknesses*

In summary, ECAs are rigorous in applying fracture mechanics to determine flaw size but have limited applications. EAs, while more broadly applicable to various threats and risks to the operation of pipeline systems, lack the formal requirements and process of ECAs. Competent engineers and robust data are required in all instances.

EAs for pipelines located in Canada are employed under the following circumstances:

- Class location designation changes

- Pipeline design
- Licensed/approved MAOP upgrade
- Defect assessment or evaluation of damage
- Change in operating conditions (product type, flow direction)
- Return to service of a pipeline after an outage
- Valve location and spacing
- Safety and reliability case management
- Reactivation after a failure
- Fitness for service of pipeline or implemented repair
- Establishing safety requirements for deviation from code requirements

In the United States, ECAs have been incorporated into the federal code[24] explicitly for the following circumstances:

- § 192.624 MAOP reconfirmation
- § 192.632 ECA for MAOP reconfirmation

Other sections of the US pipeline safety regulatory code[25] implicitly allow for EAs by using sound engineering principles or when calling for subject matter expert analysis related to:

- § 192.8 onshore gas gathering and regulated pipeline determination,
- § 192.9 alternative deadlines for Type C gathering pipeline requirements,
- § 192.179 gas transmission line valves,
- § 192.506 gas transmission lines: spike hydrostatic pressure test,
- § 192.607 Material verification
- § 192.619 MAOP for steel or plastic pipelines,
- § 192.634 gas transmission line rupture mitigation valves,
- § 192.636 gas transmission rupture responses,
- § 192.710 gas transmission lines: assessments outside of HCAs,
- § 192.712 gas transmission pipeline analysis of predicted failure pressure,
- § 192.745 gas transmission valve maintenance,
- § 192.921 gas line pipe baseline assessment,
- § 192.937 gas pipeline integrity continual process of evaluation using MAOP reconfirmation as a reassessment option,
- §193.2007 Definitions for "determine" based on sound engineering judgment as pertaining to Liquified Natural Gas (LNG) code,
- § 195.303(d) liquid pipe regulations related to engineering analysis of pre-1970s ERW pipe,
- §195.452(b)(6)(ii)) other risk-based alternative practice for liquid pipeline integrity management in HCAs, and
- §190.341 special permits.

Outstanding PHMSA notice of proposed rulemaking (NPRM) indicates ECAs are being considered for changes in gas class location[26].

[24] Title 49 CFR part 192

[25] Title 49 CFR parts 192, 193, and 195.

[26] Federal Register, Notice of Proposed Rulemaking RIN 2137-AF29, October 14, 2020, https://www.phmsa.dot.gov/regulations/federal-register-documents/2020-19872

1.4 Proposed Methodology

The proposed approach for EAs and ECAs follows a process that reflects the Plan-Do-Check-Act (PDCA) approach[27]. This approach is well established in the safety management systems literature applied to pipeline integrity management. The proposed approach is similar to the four-step process described in External[28] or Internal Corrosion Direct Assessments[29] and the eight-step FFS process outlined in API 579[30].

Plan

1. Identify the purpose of the EA
2. Determine the pipeline assets that are within the scope of the EA

Do

3. Review and document known information, including historical inspections
4. Identify the integrity threats considered within the scope
5. For each threat, review and assess:
    a. Inspection data
    b. Threat management program data (including prevention and mitigation systems)
    c. Operational, incident, and failure history
    d. Direct assessment data
    e. Risk assessment data

Check

6. Determine whether each threat hinders accomplishing the purpose of the EA based on the information assessed
7. Identify any gaps and make the necessary recommendations to fulfil the purpose of the EA

Act

8. Implement corrective actions and recommendations in a timely manner

[27] API RP 1173 "Pipeline Safety Management Systems"
[28] AMPP SP 0502 "External Corrosion Direct Assessment Methodology", 2010
[29] AMPP SP0206 "Dry-gas Internal Corrosion Direct Assessment", 2006
[30] API RP 579 "Fitness for Service Assessments,"2021 *** this was referenced earlier. No need to footnote again.

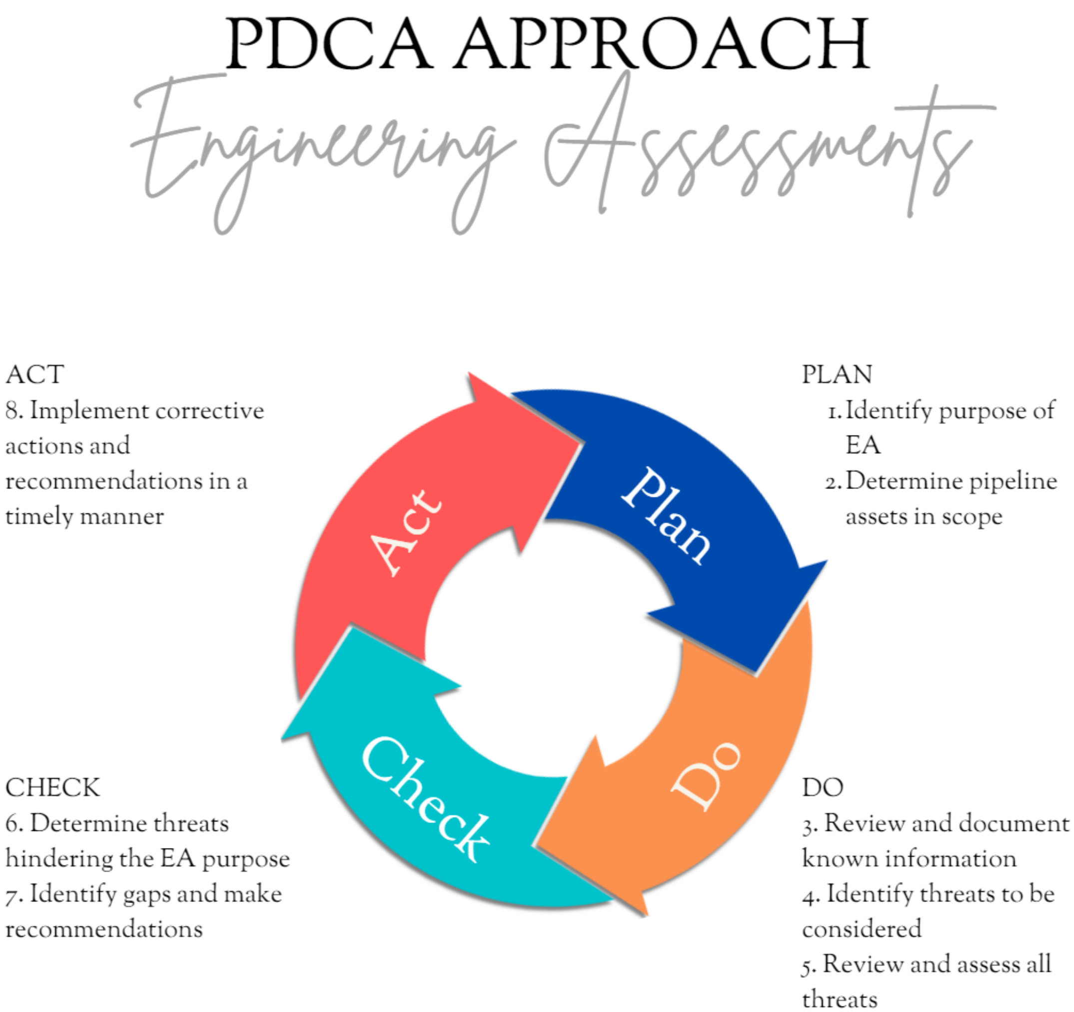

Figure 2: *PDCA - Engineering Assessments*

Figure 2 provides a simple visualization of the suggested EA approach overlaid with the PDCA cycle. Determining the purpose of the EA provides the foundation for the specific analysis considerations employed in subsequent steps. It is important to note, as will be demonstrated in the following case study, that available fracture mechanics modelling techniques common to Canadian ECAs and the API 579 FFS guidance may be utilized in step five when threats are assessed as the specific EA warrants. The suggested model for conducting an EA, must be led by a competent and qualified engineer who considers pertinent information and makes conservative assumptions in the absence of documentation.

1.5 Information Requirements

Regardless of jurisdictional determination or a specific type of EA delineation, for general FFS purposes, collection and consideration of system-specific information while conducting an assessment is essential. A competent and qualified engineer should consider at a minimum the pipeline system operational considerations, properties, threat assessments, risk assessments, inspections and repairs while conducting an EA:

1.6 Case Study

To demonstrate the EA approach, let's consider the fitness for service of a discontinued NPS 8 natural gas pipeline that is to be returned to service. Within this EA, the threats listed in Table 7 by ASME B31.8S were evaluated along with the most recent semi-quantitative risk assessment results. The proposed PDCA EC methodology is applied to this case study showing how the threat-based EA was overlaid with the semi-quantitative risk algorithm to yield a sound, engineering basis for reactivation.

1.6.1 Plan

When initiating the EA, proper planning is essential to ensure adequate analysis is performed. The purpose of this specific case study EA was to determine the FFS to reactivate a single pipeline asset. Beyond the comparing inspection feature lists and repair documentation, a concerted effort to ensure the known failure mechanism behind the historical failures was being robustly evaluated. Additional data surrounding the geohazard threat was a significant portion of the document request.

The segments comprising the asset of the study are summarized in . Another challenge with this pipeline was the presence of two short sections of unpiggable piping. We made sure to review the hydrostatic pressure test information as well as other wall thickness readings on these non piggable segments.

Segment	MOP (kPa)	O.D. (mm)	W.T. (mm)	Length (km)	SMYS[5] (MPa)	Construction
A	9930	219.1	6.4	0.1	359	Fall 2000
B	9930	60.3 168.3	5.54 7.11	N/A	241	Winter 2000
C	8275	219.1	3.9, 6.4	34.2	359	Winter 2000

Table 6: *Scope of EA Assets*

1.6.2 Do

All threats prescribed by ASME B31.8S, including interacting threats, were considered and reviewed, as reflected in Table 7.

Table 7: Threats Considered

Time-Dependent Threats	1. External Corrosion (EC), 2. Internal Corrosion (IC) and 3. Stress Corrosion Cracking (SCC).
Stable Threats	4. Manufacturing Defects (MD), 5. Construction Threat (CT) and 6. Equipment Failure (EF).
Time-Independent Threats	7. Mechanical Damage, 8. Weather Related and Outside Forces (WROF), and 9. Incorrect Operations (IO)
Interacting Threats	A coincidence of two or more threats, the result of which is more damaging than either of the individual threat alone.

Let's walk through the evaluation process for the threat of external corrosion. The effectiveness of the existing prevention and mitigation systems, such as external coatings and cathodic protection, was evaluated with in-line inspection (ILI) results along the mainline to determine the severity of the threat.

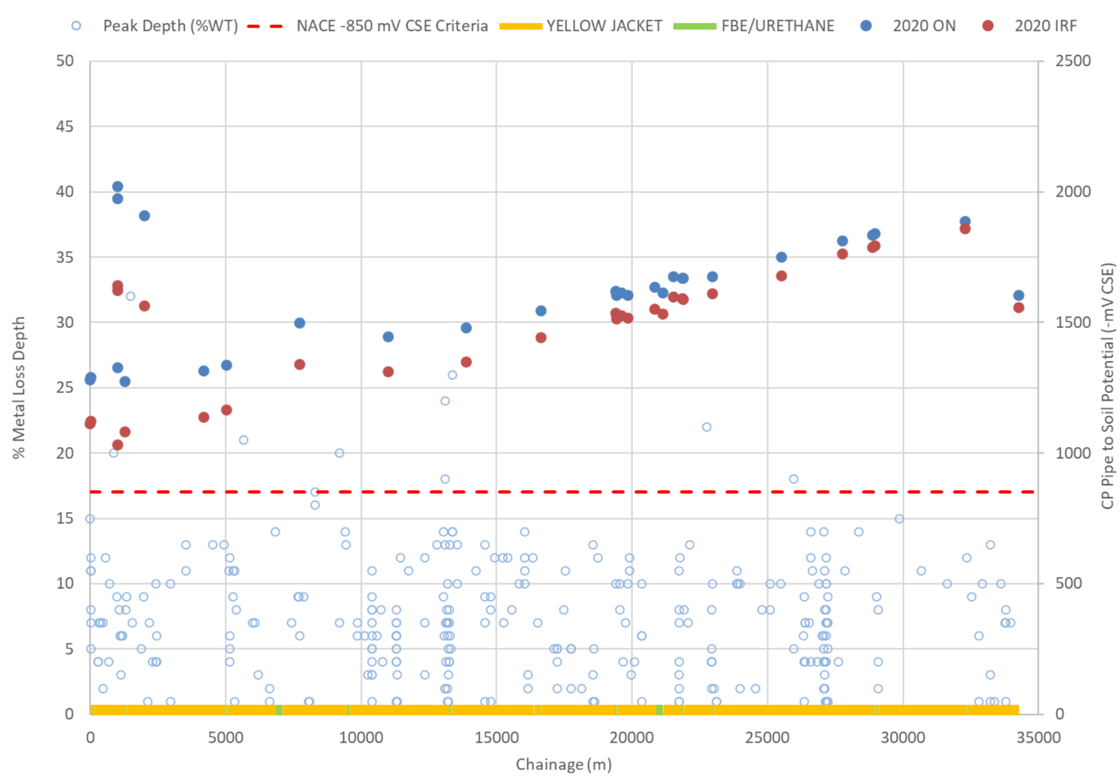

Figure 3: ILI, Coating, and CP correlation

Figure 3 demonstrates the existing prevention and mitigation systems effectively manage the threat of external corrosion from the scarcity of external metal loss anomalies reported in the ILI.

Additionally, proximity to AC powerlines was also considered for this threat due to their adverse effect and increased risk of localized accelerated corrosion and threat to worker safety. Publicly sourced spatial data[32] revealed three AC powerlines within 50 km of the in-scope pipelines. However, CP data and ILI results did not reveal any cause for concern.

The line of the EA had multiple prior inspections utilizing various magnetic flux leakage and geometry ILI technologies. After considering the repair history of addressed defects, the remaining anomalies calculated failure pressures using the ASME Modified B31G method[33] were evaluated to ensure fitness for reactivation. Table 8 provides a summary of the external metal loss anomalies remaining. The scheduled response for all the reported external metal loss anomalies was calculated using the approach described in ASME B31.8S to determine the remaining life and inspection internal after the pipeline was reactivated. This calculation revealed a minimum response time of greater than 10 years which confirmed no immediate corrective action was required for this threat before the resumption of service.

Table 8: Lowest Failure Pressure External Metal Loss Anomalies

Anomaly ID	Chainage (m)	Wall Thickness (mm)	Peak Depth (% WT)	Length (mm)	Failure Pressure[34] (kPa)	FPR[35]	Scheduled Response[36] (yrs.)
A	21822.29	3.90	15%	101	13904	1.68	> 10
B	14.34	3.90	10%	418	14045	1.70	> 10
C	14318.34	3.90	11%	195	14074	1.70	> 10
D	15978.83	3.90	9%	230	14260	1.72	> 10
E	23049.30	3.90	13%	70	14281	1.73	> 10
F	12579.74	3.90	11%	72	14418	1.74	> 10
G	12750.97	3.90	10%	81	14442	1.75	> 10
H	15904.23	3.90	14%	47	14475	1.75	> 10
I	17273.53	3.90	7%	179	14506	1.75	> 10
J	16067.77	3.90	10%	69	14513	1.75	> 10

To evaluate the effect of pressure cycles as covered by the manufacturing threat, historical operational data was plotted for a twelve-year period and compared to cycling patterns in TTO Number 5[37]. Figure 4 indicates the historical pressure and flowrate of the pipeline, which did not meet the criteria for aggressive pressure cycling. Additionally, industry guidance in ASME B31.8S

[32] "Topographic Data of Canada - CanVec Series," Government of Canada, 2017 (https://open.canada.ca/data/en/dataset/8ba2aa2a-7bb9-4448-b4d7-f164409fe056)
[33] American Society of Mechanical Engineers, Manual for Determining the Remaining Strength of Corroded Pipelines, ASME
[34] Failure Pressure is the calculated burst pressure of the pipeline with a safety factor
[35] Failure Pressure Ratio, the burst pressure divided by the MAOP
[36] [47] "Figure 7.2.1-1: Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan," ASME B31.8S Managing System Integrity of Gas Pipelines, 2020
[37] TTO Number 5, "Integrity Management Program Delivery Order DTRS56-02-D-70036," Department of Transportation Research and Special Programs Administration Office of Pipeline Safety, October 2003

and other reports[38] were considered for gas pipelines which historically have not been significantly affected by pressure cycling due to the compressible nature of gas and a limited number of cycles. Lastly, as manufacturing is a stable threat with potential defects present during the pre-commissioning pressure test, any small, survivable features remaining after the successful hydrostatic pressure test, would be resident, non-injurious features.

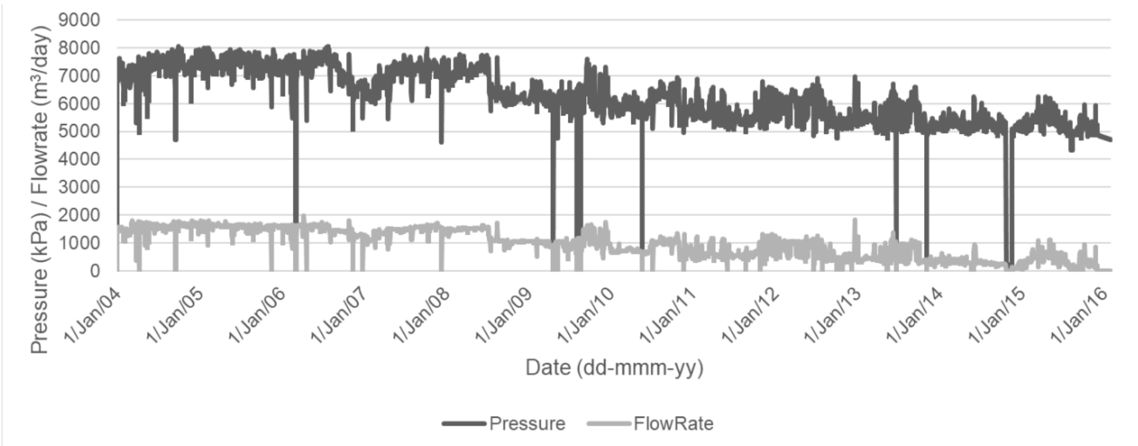

Figure 4: Pipeline Historical Pressure and Flowrate Data

The primary threat of geotechnical outside force was evaluated through a review of pertinent additional data, including ground stability slope inclinometer surveys, an asset-specific geotechnical report following landslide activity, a company damage prevention management program, and recent horizontal directional drill (HDD) remediation activity to circumvent an active fault line, was reviewed. These preventatives and mitigative measures were deemed adequate to manage the threat of outside geotechnical forces.

The other five threats not discussed in this paper and interacting threats were evaluated based on industry guidance and information available by competent and qualified engineers. The sound engineering practices employed and asset-specific analysis conducted on a threat basis were documented in the EA report. The report was peer-reviewed and accepted before delivery to the asset operator.

1.6.3 Check

During the EA review, adequate data was provided to determine FFS, and no threats were identified as unmitigated that could hinder the EA's purpose of reactivating the asset. Assumptions were documented, and recommendations were provided in the final report.

As an additional check of the desktop engineering assessment conducted, risk results were also evaluated by calculating the failure frequencies for all threats based on available information and a semi-quantitative risk model. For this pipeline, the risk results identified third-party mechanical damage as the major driver, with failure frequencies at all points except one being below 10^{-4} ruptures/km-year as shown in Figure 5. The drastic dip in failure frequencies near the 21,000 m

[38] J. Keifner and M.J. Rosenfield, GRI Report GRI-04/0178, "Effects of Pressure Cycles on Gas Pipelines," September 2004.

chainage is from a newly replaced HDD section of pipe. The risk algorithm yielded third-party damage as the major driver based on the depth of cover for the specific pipeline, though the actual pipeline depth met or exceeded the regulatory requirements for cover across the length of the pipeline. As the HDD remediation was performed before the risk results were calculated, outside forces were not a driving threat.

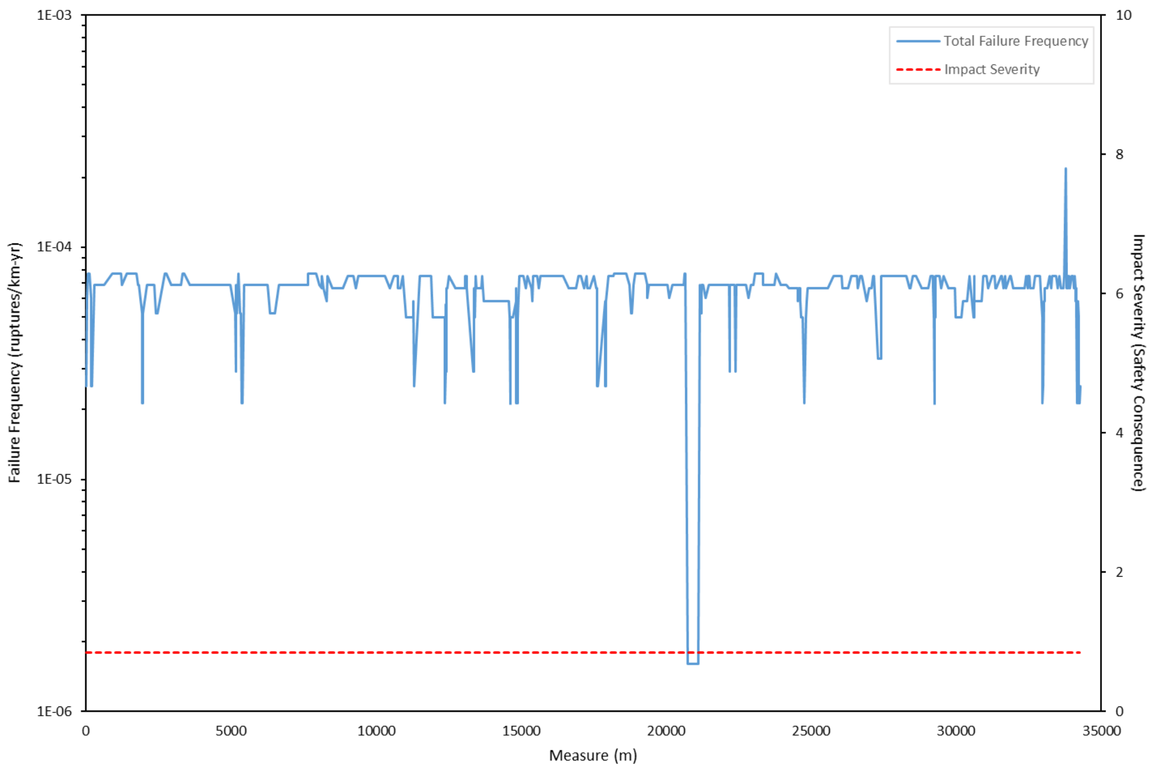

Figure 5: Total Failure Frequency Profile

The engineers working on the desktop EA as well as those responsible for the semi-quantitative risk assessment, agreed the separate perspectives of threat-based assessment versus the computational risk assessment provided a comprehensive and independent evaluation of the assets state of integrity. This complete review instilled integrity assurance in the resulting reactivation of the asset system.

Not necessarily an objective of the specific EA scope, but a consideration is the financial savings of performing a robust and sound engineering assessment to determine reactivation FFS instead of running another non-destructive pipeline ILI or other assessment. As the pipeline in question was out of service at the time of the EA, significant costs to perform an assessment would be incurred if this method was selected.

1.6.3 Act

Based on the threat-guided EA and the computational risk results, the pipeline was determined fit to resume service. Two recommendations, summarized by threat in Table 9, were suggested following the EA to maintain the asset's integrity over the remaining operational life.

Table 9: EA Recommendations

Item	Threat	Recommendations
A	Weather Related and Outside Forces	Perform a strain analysis of the next ILI assessment data set to evaluate the potential for previously unidentified land movement to affect the pipeline along the ROW.
B	Stress Corrosion Cracking	Evaluate future metal loss ILI data for the presence of general corrosion occurring near girth welds to provide insight into the coating condition at joints and the potential for increased susceptibility to SCC.

Conclusions

The proposed methodology and the associated case study demonstrate the effectiveness of employing a robust and comprehensive approach to EAs or ECAs to determine fitness for service. The proposed approach employs the strengths of both EAs and ECAs, namely the incorporation of threat analysis, risk assessment results, and fracture mechanics to provide pipeline operators with objective and technically sound results and tailored recommendations.

Additionally, in circumstances where no data or low confidence data is available, the involvement of one or more subject matter experts or competent engineers to conduct the EA or ECA using conservative assumptions is invaluable.