GUIDELINES FOR PARALLEL CONSTRUCTION OF PIPELINES

Document Prepared: December 2025

Technical support to The INGAA Foundation, Inc. by:

EXP
2510 Miccosukee Road, Suite 200
Tallahassee, FL 32308
USA

Document Prepared: December 2025

The INGAA Foundation, Inc.

Steering Committee:

Matthew Moore	Pioneer Truck Lines
Jared Ciarella	Gulf Companies
Christopher Smith	INGAA
Joan Dreskin	INGAA
Scott Gilles	HDD Company
Russell Morris	Air Products
Bridger Durham	Driver Pipeline
Peter Staudenmeier	CEC Inc.
Ian Kornfeld	YPP USA
David Gregory	Kleinfelder
Elaine Pacheco	EXP
Randy Head	Boardwalk
Shawn Miller	BHE GT&S

Document Prepared: December 2025

The INGAA Foundation, Inc.

GUIDELINES FOR PARALLEL CONSTRUCTION OF PIPELINES

December 2025

1. Introduction

1.1. Context

1.1.1. Background and Evolution of Parallel Construction

Pipeline construction and corridor densification have continued well beyond the timeframe anticipated when these Guidelines were originally published in 2011. Over the past decade, regulatory, environmental, and land-use policies in North America and internationally have systematically prioritized the use, widening, or extension of existing rights-of-way (ROW) for new pipelines and linear infrastructure, rather than the creation of entirely new corridors. This shift reflects both environmental stewardship priorities, reducing fragmentation of land and ecosystems, and practical economic considerations that favor established transmission corridors.

Concurrent with this policy trend, corridor densification has accelerated significantly. New pipelines are increasingly co-located with diverse energy and utility infrastructure, including:

a) Energy infrastructure
- Electric transmission and distribution lines (AC and DC)
- CO_2 pipelines (for enhanced oil recovery or carbon capture and sequestration)
- Hydrogen pipelines
- Distributed renewable energy infrastructure

b) Conventional utilities
- Water and wastewater systems
- Telecommunication and fiber optic cables
- Hydrogen and compressed air storage systems

c) Transportation infrastructure
- Highways and expressways
- Railways and light rail systems

This densification has made parallel construction the default configuration for the majority of new pipeline projects, rather than the exception. As a result, the ability to safely design, construct, and operate pipelines in shared corridors has become a critical competency for the entire pipeline industry.

1.1.2. Evolution of Knowledge and Standards

Over the same period, 2011 to 2025, incident investigations, research programs, and the emergence of new technical standards have substantially advanced industry understanding of interaction risks between co-located facilities. Key developments include:

a) Regulatory and guidance evolution:

- API Recommended Practice 1172 (2019) – *Construction parallel to existing underground transmission pipelines*, providing comprehensive methodology for interaction risk assessment and mitigation
- CSA Z662-2019/2023 (Canadian Standards Association) – Updates to oil and gas pipeline systems standards, including enhanced geohazard assessment and parallel facility coordination provisions
- AS 2885.1 and related standards (Australian Standards) – Comprehensive pipeline design and construction provisions with explicit parallel facility requirements
- IGEM/TD/1 (UK standards) – Guidance for buried pipeline works in the vicinity of other utilities
- PHMSA Integrity Management Rules (49 CFR §192.911, §195.452) – Enhanced emphasis on operational hazards and external threat identification, including parallel facility risks

b) Specialized technical criteria:

- INGAA/DNV GL AC Interference Severity Matrix – Quantitative guidance for assessing and mitigating AC induced voltage risks
- Geohazard assessment methodologies – Enhanced understanding of landslide, seismic, and subsidence risk in parallel corridors
- Interaction hazard classification – Systematic frameworks for characterizing and prioritizing mechanical, thermal, electrical, and operational interaction risks

c) Industry case studies and lessons learned:

- Incident databases and forensic investigations documenting damage mechanisms in parallel corridor environments
- Case studies from major pipeline projects demonstrating effective coordination frameworks and technical solutions
- Research funded by organizations such as the INGAA Foundation and Pipeline Research Council International (PRCI).

These developments have generated a body of knowledge that did not exist in 2011, when the INGAA Foundation first developed its *Guideline for Parallel Construction of Pipelines*, and has fundamentally improved the industry's capacity to manage parallel corridor risks.

1.1.3. Purpose and Objectives of the Revised Guidelines

These revised Guidelines are updated to reflect the current state of engineering practice and regulatory expectations for parallel pipeline projects. The Guidelines provide risk-based, lifecycle guidance for the planning, design, construction, commissioning, and post-construction integrity management of new pipelines constructed parallel to, or otherwise in close proximity to, existing underground transmission pipelines and related energy infrastructure.

Primary Objectives:

The primary objectives of these Guidelines are to:

a) **Preclude unsafe conditions and minimize damage likelihood** – Establish preconstruction and construction controls that eliminate or substantially reduce the risk of damage to existing facilities during new pipeline construction, and conversely, ensure that construction by existing facility operators does not jeopardize the integrity of newly-constructed pipelines

b) **Manage interaction hazards over the full lifecycle** – Address mechanical, thermal/fire, electrical (AC/CP), geotechnical, and operational/organizational interaction hazards over the complete operating life of co-located facilities, recognizing that risks do not end with the completion of construction but continue through design, operations, maintenance, and decommissioning;

c) **Establish clear stakeholder expectations and governance** – Define expectations for stakeholder engagement and interface management, including explicit roles and responsibilities for:
   - Pipeline operators (new and existing)
   - Engineering and design professionals
   - Construction contractors and environmental professionals
   - Regulators and permitting authorities
   - Landowners and community stakeholders
   - One-call centers and damage prevention programs

d) **Align with recognized good engineering practice (RAGAGEP)** – Promote consistent application of:
   - API RP 1172 (Construction Parallel to Existing Transmission Pipelines)
   - CSA Z662 (Oil and Gas Pipeline Systems – Canada)
   - AS 2885.1 (Pipelines – Design and Construction – Australia)
   - IGEM/TD/1 (Buried Pipeline Works – UK)
   - ASCE seismic and geohazard guidelines (United States)
   - PHMSA and FERC regulatory requirements (United States)
   - Provincial and regional regulations (Canada and other jurisdictions)

e) **Support safer, more efficient corridor development** – Provide practical guidance that enables pipeline operators and their contractors to plan, design, construct, and operate parallel pipelines safely while meeting commercial timelines and environmental stewardship objectives.

1.1.4. Scope of the Guidelines

1.1.4.1. Primary Focus

These Guidelines are focused on interaction between gas and liquid hydrocarbon transmission pipelines operating at pressures and scales that are subject to regulatory oversight by agencies such as PHMSA, FERC, state regulatory authorities, or Canadian provincial regulators.

1.1.4.2. Applicability to Other Infrastructure

Many of the principles and risk management approaches in these Guidelines apply to parallel construction involving other subsurface and aboveground infrastructure, including:

a) Electrical infrastructure:
- High-voltage AC and DC transmission lines
- Distribution circuits and substations

b) Other energy infrastructure:
- CO_2 pipelines
- Hydrogen pipelines
- Water and wastewater transmission lines
- Fiber optic and communication cables

c) Transportation infrastructure:
- Highways, expressways, and service corridors
- Railways and light rail systems

Note on complementary standards: Where other Recommended Practices or standards govern specific facility interactions (e.g., DNV GL criteria for pipelines co-existing with electric power lines, local utility standards for water/sewer crossing design), these Guidelines are intended to be complementary and consistent with those standards. In cases of apparent conflict, project-specific risk assessment and regulatory guidance should reconcile the requirements.

1.1.5. Baseline and Project-Specific Measures

1.1.5.1. Guidelines as Baseline Expectations

The measures and recommendations in these Guidelines constitute baseline expectations for parallel construction projects. They represent a consolidation of current engineering practice, regulatory expectations, and lessons learned from executed projects.

1.1.5.2. Project-Specific Risk-Based Enhancements

Project-specific circumstances will often require additional, risk-based measures beyond this baseline, including:

a) High-Consequence Areas (HCAs) – Segments where pipeline failure could potentially result in a fatality or injury to a member of the general public; typically requiring more conservative design and enhanced integrity management

b) Moderate-Consequence Areas (MCAs) – Segments with potential for significant but not catastrophic consequences; typically requiring intermediate levels of control and monitoring

c) Sensitive environmental terrain:

- Wetlands, surface water bodies, aquifer protection zones
- Protected ecosystems and sensitive habitats
- Indigenous cultural and sacred sites

d) Geohazard-prone terrain:

- Active or historic landslide zones
- Seismic zones (particularly near active faults)
- Subsidence or karst terrain
- Riverine scour and flood-prone corridors

e) Novel services and pressures:

- Hydrogen pipelines (subject to enhanced material and crack propagation considerations)
- CO_2 pipelines (subject to corrosion, crack propagation and decompression risks)
- High-pressure water or slurry lines
- Cryogenic services

f) Complex interaction environments:

- Multiple parallel facilities (three or more pipelines in close proximity)
- Combined AC power line and pipeline co-location with geohazard exposure
- High-traffic corridors with frequent third-party construction

1.1.5.3. Regulatory Authority and Flexibility

These guidelines are not meant to supersede or replace regulatory requirements, nor is it intended to be all inclusive of the applicable regulatory requirements. Nothing in these Guidelines prevents parties from adopting more stringent controls where justified or mandated by risk assessment, regulatory requirements, or project-specific circumstances. Instead, view this data as supportive and complementary to any operating requirements.

1.1.6. **Definition of "Parallel" and Applicability**

1.1.6.1. Encroachment Area as the Defining Criterion

Whether or not construction is considered to be "parallel" and therefore subject to the full scope of these Guidelines, is established by the beginning and ending of the Encroachment Area as defined in Section 2.0 (Definitions).

The Encroachment Area is the geographic zone where a new pipeline and an existing facility are close enough that:

a) Construction activities for the new pipeline could reasonably pose a risk to the existing facility, or

b) Long-term co-location creates the potential for mechanical, thermal, electrical, geohazard, or operational interaction risks during the service life of either facility.

1.1.6.2. No Minimum Length Threshold

The steering committee that developed these Guidelines considered and ultimately rejected specifying a minimum parallelism length threshold (e.g., "Guidelines apply only where parallelism exceeds 500 feet") under which these Guidelines would apply.

The group arrived at a consensus that application of these Guidelines was appropriate regardless of the length the existing and new facilities are in parallel. This decision reflects the understanding that even short parallel segments can pose significant interaction risks (e.g., mechanical interaction at a crossing point, thermal interaction near a high-pressure or hot facility, AC interference in a congested corridor).

Conversely, very short segments with clearly identified and manageable risks (e.g., a 50-ft crossing with greater than 25 ft separation at nominal operating conditions) may be managed through simplified risk assessment and control procedures but are not excluded from the Guidelines on the basis of length alone.

1.1.7. Role of Contractors and Project Team Members

While the primary emphasis of these Guidelines is on the interaction between existing pipeline operators and those operators planning to construct new pipelines in parallel, it is recognized that the effective implementation of these Guidelines depends on the engagement and vigilance of the entire project team.

1.1.7.1. Contractor and Consultant Responsibilities

Contractors working on behalf of pipeline operators, including but not limited to:

a) Environmental and survey professionals

b) Design engineers and specialized consultants (geotechnical, AC interference, geohazard specialists)

c) Construction contractors and subcontractors

d) Operators of excavation and earth moving equipment

Should:

- Engage in work practices that are in conformance with these Guidelines

- Apply vigilance in identifying unanticipated circumstances that may indicate a risk to existing or new facilities (e.g., unexpected subsurface conditions, facility locations differing from records)
- Report deviations, near-misses, and safety concerns promptly to the project management team
- Participate in continuous improvement by providing feedback on the adequacy of controls and opportunities for enhanced efficiency.

1.1.7.2. Integration into Contract Documents

It is strongly encouraged that these Guidelines be:

a) Referenced explicitly in contract documents executed with contractors, subcontractors, and consultants

b) Incorporated by reference or attachment, with modifications as necessary to reflect project-specific requirements

c) Integrated into project safety plans, quality assurance procedures, and construction readiness reviews.

1.2. Relationship with Regulations, Codes, and Standards

1.2.1. Regulatory Framework

These Guidelines are not a substitute for applicable laws and regulations. Users of these Guidelines are responsible for full compliance with:

1.2.1.1. United States Federal Regulations

a) PHMSA Pipeline Safety Regulations – 49 CFR Parts 192 (Natural Gas Pipelines) and 195 (Hazardous Liquid Pipelines), including provisions for:

- Damage prevention (§192.631, §195.2)
- Design and construction standards
- Corrosion control and cathodic protection
- Integrity Management programs (§192.911, §195.452)
- Operations and maintenance

b) FERC Siting and Environmental Requirements – 18 CFR §380.15 and related provisions, for interstate natural gas pipelines, including:

- Certificate of Public Convenience and Necessity and associated conditions
- Pre-filing, filing, and notice requirements
- Environmental review and permitting
- Coordination with existing facility operators

1.2.1.2. Canadian Regulations

a) CSA Z662-2019/2023 – Oil and Gas Pipeline Systems (National Standard of Canada), including design, construction, testing, commissioning, and operations provisions applicable to all provinces

b) Provincial pipeline regulations (e.g., Alberta Energy Regulator, British Columbia Oil and Gas Commission, provincial Environmental Protection Acts)

c) One-call center regulations and damage prevention laws (e.g., Alberta One-Call, British Columbia One-Call)

d) Environmental assessment requirements (Canadian Environmental Protection Act, provincial EAs).

1.2.1.3. Other Jurisdictions

a) Australian Standards – AS 2885.1 and related standards for oil and gas pipeline design and construction;

b) UK Standards – IGEM/TD/1 and related guidance for buried pipeline works;

c) International standards – ISO 13623 (Industrial pipelines – General rules and safety).

1.2.2. Relationship with Industry Codes and Recommended Practices

These Guidelines are explicitly aligned with and reference the following industry standards:

1.2.2.1. API Standards and Recommended Practices

a) API RP 1172-2019 – *Recommended Practice for Construction Parallel to Existing Underground Transmission Pipelines* – Provides comprehensive methodology for interaction risk assessment, design coordination, construction controls, and post-construction monitoring. These Guidelines are directly consistent with API RP 1172 and in many cases expand on its provisions with additional detail and case studies.

b) API RP 1109 – *Marking of Subsurface Facilities* – Referenced for pipeline marker design and placement standards.

c) API RP 1130 – *Calculating the Secondary Response of Onshore and Offshore Production Piping* – Referenced for vibration and dynamic effects assessment.

d) API Standard 579 – *Fitness for Service* – Referenced for pipeline damage assessment and integrity evaluation methodologies.

1.2.2.2. NACE/AMPP Standards

a) NACE/AMPP SP0169 – *Control of External Corrosion on Underground or Submerged Metallic Piping Systems* – Referenced for cathodic protection system design and monitoring.

b) NACE/AMPP TM0497-2015 – *Measurement Techniques Related to Criteria for Cathodic Protection on Underground Metallic Piping Systems* – Referenced for CP data collection and interpretation.

1.2.2.3. Other Industry Standards

a) ASCE 38-22 – *Standard for the Collection and Depiction of Existing Subsurface Utility Information* – Referenced for Subsurface Utility Engineering (SUE) quality levels and spatial accuracy requirements.

b) ASCE Seismic Guidelines – Referenced for geohazard and seismic risk assessment in parallel corridors.

c) INGAA/DNV GL AC Interference Severity Matrix – Referenced for AC interference screening and severity classification.

d) Common Ground Alliance (CGA) Best Practices – Referenced for damage prevention, one-call center coordination, and stakeholder engagement.

1.2.3. Complementary Use of Guidelines and Standards

Where these Guidelines reference external documents (API RP 1172, NACE/AMPP standards, DNV GL criteria, CSA Z662, AS 2885.1, IGEM/TD/1, or others), they are intended to:

a) Support consistent application of recognized and accepted good engineering practices (RAGAGEP);

b) Provide flexibility for project teams to select methodologies and tools appropriate to project-specific risks and constraints;

c) Maintain compatibility with existing project delivery frameworks and international standards;

d) Encourage continuous improvement as new methods and technologies emerge.

1.2.4. Hierarchy of Requirements

In cases where potential conflicts arise between these Guidelines, applicable regulations, and industry standards, the following hierarchy applies:

- Applicable laws and regulations (PHMSA, FERC, CSA Z662, provincial laws, local ordinances);
- These Guidelines and referenced industry standards (API RP 1172, CSA Z662, AS 2885.1, IGEM/TD/1, ASCE standards);
- Project-specific risk assessment outcomes and risk-based risk management decisions;
- Company policies and engineering standards internal to the organizations involved.

Where apparent conflicts exist, the responsible engineer and project team should document for the Pipeline Owner/Operator the basis for resolution and ensure that the selected approach provides equivalent or superior risk management to the alternatives.

1.3. Organization and Use of These Guidelines

1.3.1. Document Structure

These Guidelines are organized into eight major sections:

a) Section I: Introduction – Scope, objectives, and regulatory context (this section)

b) Section II: Definitions – Terms, acronyms, and definitions specific to parallel pipeline projects

c) Section III: General Principles and Stakeholder Engagement – Foundational commitment to joint responsibility and frameworks for multi-party coordination

d) Section IV: Preconstruction – Route due diligence, risk assessment, encroachment agreements, and engagement with existing facility operators

e) Section V: Design and Engineering – Design criteria, separation distances, specialized assessments (AC/CP interference, geohazard), and risk control design

f) Section VI: Construction – Construction planning, controls, monitoring, and quality assurance specific to parallel corridors

g) Section VII: Commissioning and Post-Construction – Baseline surveys, monitoring programs, and long-term integrity management of co-located facilities

h) Section VIII: Governance and Interface Management – Roles, responsibilities, decision-making authority, and deviation management

1.3.2. How to Use These Guidelines

These Guidelines may be used in several ways:

a) As a reference during project execution – Project teams can reference specific sections addressing their current project phase (routing, design, construction, etc.)

b) As a specification incorporated into project contract documents – These Guidelines may be referenced in owner-contractor agreements, engineering services contracts, and other project agreements, with project-specific modifications as needed

c) As a basis for developing company policies or project standards – Organizations may use these Guidelines as a foundation for developing their own parallel pipeline procedures, adapted to company-specific practices and organizational structure

d) As a training and awareness resource – These Guidelines may be used in training programs for engineers, inspectors, field supervisors, and other personnel involved in parallel pipeline projects

1.3.3. Proportionality and Scalability

These Guidelines are designed to be proportional to project risk and complexity. Not all sections will apply with equal emphasis to all projects:

a) A relatively simple short-distance crossing of two pipelines with adequate separation may require abbreviated versions of risk assessment (Section 4.2) and design (Section 5.0)

b) A complex multi-mile parallel segment in an HCA/MCA with geohazard exposure and AC power line co-location may require the full suite of assessments and controls described in these Guidelines

c) Project teams are encouraged to use professional judgment to scale the rigor of application to match the risk profile, rather than applying every element uniformly to all projects

2. Definitions and Key Terminology

The following terms and acronyms are fundamental to understanding and applying these Guidelines. Where terms are not defined herein, they should have the meanings assigned by applicable regulations (PHMSA 49 CFR Parts 192/195, CSA Z662, AS 2885.1, IGEM/TD/1) or recognized industry standards.

2.1. Core Definitions

2.1.1. Parallel Construction

Construction of new pipeline facilities in close proximity to existing subsurface or aboveground facilities within a shared corridor, such that construction or operation of one facility can materially influence the safety, integrity, reliability, or accessibility of another.

The extent of Parallel Construction is established by the beginning and ending of the Encroachment Area. Facilities need not be literally parallel (running side-by-side) to be subject to these Guidelines; crossing interactions and other close-proximity configurations that create mutual risk are included.

2.1.2. Encroachment Area (EA)

The geographic zone where construction activities or long-term co-location can reasonably affect the safety, integrity, or operability of an existing facility. The Encroachment Area is defined by distance from the centerline of the existing facility:

a) Primary criterion: Horizontal distance of 50 feet (15 m) from the centerline of the existing facility, or

b) Alternative criterion: Within the existing facility's right-of-way (ROW), easement, or other legal corridor, whichever distance is greater.

Additional distance adjustments: The Encroachment Area extent may be expanded beyond the primary criterion to account for site-specific conditions, including:

- Topography – Side-hill cuts, steep slopes, embankments
- Cathodic protection systems – Distributed anode beds, impressed current anode beds, or test station arrays extending beyond immediate facility vicinity
- Geohazard conditions – Landslide zones, seismic faults, subsidence areas where ground movement affects both facilities
- Environmental constraints – Wetlands, water body buffer zones, aquifer protection areas
- Facility size and operating conditions – Large-diameter pipelines, high-pressure lines, high-temperature services
- Underground obstruction – Rock outcrops, water tables, existing utilities affecting excavation depth and working area
- Construction sequencing – Temporary staging areas, material stockpiles, equipment access zones

Where the Encroachment Area is adjusted beyond 50 feet, the basis for the adjusted distance should be documented in the project design dossier and incorporated into encroachment agreements.

2.1.3. Active Excavation Area (AEA)

The zone where active excavation, trenching, boring, or other ground disturbance operations are occurring or planned to occur in close proximity to an existing facility.

Edge of disturbance within 25 feet (7.5 m) of the centerline of the existing facility, unless site-specific conditions (e.g., rock, utilities, confined spaces) require greater clearance above ground, underground, or both.

The AEA is the zone where construction damage risk is highest and where the Existing Facility Representative (EFR) maintains continuous presence and authority to halt work if safety or integrity is at risk. Within the AEA, Table 6-1 (Mandatory Construction Controls) applies.

2.1.4. Excavation Tolerance Zone (ETZ)

The closest approach zone to an existing facility, where excavation or ground disturbance poses direct contact or damage risk.

The extent of this zone is 2 feet (0.6 m / 24 inches) from the edge of the existing facility, or the distance mandated by applicable state or provincial law, whichever is greater.

Note that this definition is intentionally more conservative than the CGA Practice 5-19 default of 18 inches, reflecting the critical nature of transmission pipeline protection.

Within the ETZ, non-destructive excavation (soft-dig) or daylighting methods (vacuum excavation, hand digging) are mandatory unless the existing facility is explicitly confirmed to be absent or abandoned.

2.1.5. Construction Envelope (CE)

The spatial zones around an existing facility within which construction activity is expected to influence safety or integrity.

The Construction Envelope consists of three nested zones:

a) Encroachment Area (EA) – Outer zone (≤50 ft from existing facility centerline)

b) Active Excavation Area (AEA) – Intermediate zone (≤25 ft from existing facility centerline)

c) Excavation Tolerance Zone (ETZ) – Inner zone (≤2 ft from existing facility edge or per state law)

Within the CE, engineering design should define:

- Permitted and prohibited construction methods (see Table 6-1)
- Requirements for Existing Facility Representative (EFR) presence and authority
- Soft-dig and daylighting expectations at conflict points
- Blasting and vibration limits (see Table 6-2)
- Temporary operating restrictions (pressure reduction, shutdown) applicable to existing lines during construction

2.1.6. Operations Envelope (OE)

The spatial extent within which long-term interactions such as AC induction, cathodic protection shielding, thermal escalation, and geohazard coupling between parallel facilities must be evaluated and managed. OE distances are risk-based and may extend significantly beyond the Construction Envelope.

The Operations Envelope is divided into three risk-tiered zones relative to the existing facility centerline. Tier assignment triggers the level of analysis required for AC induction, CP interference, thermal/fire escalation, mechanical interaction under rupture, and geohazard-seismic coupling.

2.1.7. Interface Management Plan (IMP)

A formal, documented plan that defines the organizational structure, roles, responsibilities, communication protocols, decision-making authorities, and deviation/change management procedures for all stakeholders involved in parallel pipeline planning, design, construction, commissioning, and operations.

The IMP serves as the governing document for inter-operator and multi-stakeholder coordination, ensuring that:

- Decisions affecting both facilities are made transparently with appropriate approvals
- Communication is clear, timely, and documented
- Deviations from agreed scope, design, or procedures are identified, evaluated, and approved
- Lessons learned and corrective actions are captured and implemented

The IMP may be a standalone document or incorporated by reference into encroachment agreements (Section 4.5). The IMP should be updated throughout the project lifecycle as organizational changes, project scope refinements, or lessons learned warrant revision.

2.1.8. Encroachment Agreement

A formal contractual agreement executed between the new pipeline operator and the existing facility operator(s), documenting:

a) Encroachment Area and Construction/Operations Envelope definitions

b) Separation distances and alignment constraints

c) Construction-phase controls (EFR assignment, soft-dig requirements, vibration limits, pressure reduction criteria, blasting procedures)

d) Post-construction baseline surveys and long-term monitoring cadences

e) Interface Management Plan roles and decision authorities

f) Cost allocation for shared mitigation or monitoring

g) Liability, insurance, and dispute resolution provisions

Encroachment agreements should be executed before construction mobilization and prior to initiation of any ground disturbance or SUE activities within the Encroachment Area.

2.1.9. Designated Contact

The single point of contact designated by each organization (new pipeline operator and existing facility operator) responsible for:

- Coordinating planning and design communications
- Ensuring timely information exchange and document review
- Facilitating escalation and issue resolution during project phases
- Maintaining a log of key communications, decisions, and agreements affecting the parallel facility interface

Each organization should identify Designated Contacts at the project initiation meeting and maintain current contact information (name, title, phone, email) accessible to all parties.

2.1.10. Existing Facility Representative (EFR)

The person designated by the existing facility operator's project management and authorized to represent the existing operator's interests during construction activities within the Active Excavation Area (AEA).

The EFR should be:

- Competent in the operation and integrity of the existing facility (trained on facility specifications, design limits, critical areas, and damage indicators)
- Knowledgeable in construction practices affecting the facility (excavation equipment, soft-dig techniques, hydrostatic test procedures)
- Authorized to halt work immediately if conditions develop that pose a risk to the safety or integrity of the existing facility

The EFR should maintain continuous presence on-site during all ground disturbance operations within the AEA or may delegate presence to an authorized deputy with equivalent competency.

Authority and responsibility:

- Authority to stop work without prior approval if imminent risk is identified
- Responsibility to monitor deviations (unauthorized equipment, inadequate separation, unexpected subsurface conditions)
- Obligation to immediately notify the project management team and new operator's Site Supervisor of any concerns
- Requirement to document daily observations in a field log

2.1.11. Co-Location Engineer of Record

Definition: The independent professional engineer (or senior engineer designated by one of the operators) responsible for:

- Verifying that design and construction decisions comply with encroachment agreements and Interface Management Plan
- Conducting engineering evaluation of deviations and recommending approval or rejection
- Maintaining objectivity and accountability across multiple operators' interests
- Signing off on critical design, construction, and post-construction activities

The Co-Location Engineer of Record should be appointed prior to final design completion and identified in the Interface Management Plan and encroachment agreement.

2.1.12. **Due Diligence Corridor** is equal to the width of the proposed survey corridor plus 50 feet on each side. The survey corridor is the corridor width typically used for biological surveys, for example.

The geographic corridor encompassing all existing and planned infrastructure that could be affected by the new pipeline construction or operation.

The Due Diligence Corridor is typically defined as:

a) The width of the proposed pipeline survey corridor (used for biological surveys, environmental baseline, topographic surveys), plus

b) 50 feet (15 m) on each side of the survey corridor centerline.

The Due Diligence Corridor may be expanded beyond this default to account for:

- Geohazard extent (landslides, subsidence zones)
- AC power line right-of-way widths
- Known buried utility corridors or utility easements
- Environmental or regulatory setback requirements

The Due Diligence Corridor defines the geographic scope for facility inventory, risk screening, and initial Subsurface Utility Engineering (SUE).

2.1.13. **Shared Corridor / Co-located Corridor:** A right-of-way or corridor within which two or more pipelines or utilities are installed with overlapping influence zones over a meaningful length.

A right-of-way or corridor area within which two or more pipelines, utilities, or infrastructure systems are installed or planned with overlapping influence zones (Construction Envelope or Operations Envelope) over a meaningful distance (typically ≥100 feet / 30 m). It is characterized by:

- Multiple facility operators with mutual dependencies
- Potential for construction and operational interactions
- Shared or adjacent easements or land rights

2.1.14. Mechanical Interaction

Physical contact, stress transfer, or structural coupling between facilities resulting from construction activities, equipment loading, ground movement, or rupture/blast event in one facility affecting the other.

Examples:

- Excavator bucket striking an existing pipeline
- Consolidation settlement or slumping of new trench affecting existing facility position
- Blast-induced vibration or crater formation adjacent to an existing pipeline
- Pipe-on-pipe contact under large ground deformation (landslide, earthquake)

2.1.15. Thermal Interaction

Temperature escalation or thermal stress transfer between facilities operating at different temperatures or subject to thermal transients.

Examples:

- Heat transfer from a hot-oil or hot-gas pipeline to an adjacent pipeline
- Thermal stress concentration at crossing points where temperature differences are greatest
- Thermal cycling fatigue in adjacent pipelines caused by operational transients

2.1.16. Electrical Interaction: AC Induction and Cathodic Protection (CP) Interference

Coupling of electrical potential or current between parallel facilities through conductive media (soil, metallic bonds, cathodic protection systems).

AC Induction:

- Transfer of voltage and current from AC power lines to nearby pipelines, driven by electromagnetic coupling
- Risk: Personnel hazard (touch voltage >15 V potentially fatal), AC corrosion (accelerated pitting at coating defects), CP interference
- Mitigation: Increased separation, gradient control mats, bonds, grounding improvements.

CP Interference:

- Shielding or polarization of one pipeline's cathodic protection system by the anode bed or distributed anode system of an adjacent pipeline
- Risk: Loss of CP protection, accelerated corrosion, especially in low-resistivity soils
- Mitigation: CP system redesign, decoupling measures (bonds, isolation), test station expansion and relocation

2.1.17. **Geohazard Interaction**

Coupling of geotechnical or seismic hazards affecting multiple co-located facilities simultaneously or differentially.

Examples:

- Landslide affecting both pipelines, with differential displacement causing ovalization or buckling
- Seismic ground motion causing simultaneous ovalization and local buckling in adjacent lines
- Subsidence or liquefaction causing settlement and loss of support
- Riverine scour removing cover and exposing both pipelines

Mitigation strategies: Alignment offset to avoid most active hazard zone, strain-based design, differential burial strategies, ground improvement, enhanced monitoring.

2.1.18. **Operational/Organizational Interaction**

Risk arising from coordination failures, miscommunication, or operational conflicts between facility operators during construction or operations.

Examples:

- Misalignment of shutdown windows (existing operator not informed of planned hot work on new pipeline)
- Inadequate isolation of existing facility during construction
- Lack of clarity on emergency response procedures when both facilities are affected

Mitigation: Interface Management Plan with clear roles, permit-to-work system, joint emergency response planning.

2.1.19. **High-Consequence Area (HCA)**

A segment of pipeline, as defined in 49 CFR Part 192.903 (for natural gas) or 49 CFR Part 195.2 (for hazardous liquid), where a rupture or uncontrolled release could reasonably result in a fatality or serious injury to a member of the public.

Triggering conditions:

- One or more persons per year within a 660-foot radius; or
- Schools, hospitals, retirement facilities, or other sensitive institutions within defined distance; or
- Designated drinking water intakes within specified distance.

Regulatory implications: HCA segments require enhanced design, more frequent inspection/monitoring, and integrity verification programs.

2.1.20. **Moderate-Consequence Area (MCA)**

A segment of pipeline where a rupture or release could result in economic loss, environmental impact, or injury (but not fatality) to potentially affected populations or resources.

MCAs typically have lower population density than HCAs but still warrant enhanced monitoring and maintenance relative to low-consequence areas.

2.1.21. **Subsurface Utility Engineering (SUE)**

The professional methodology and practices for identifying, locating, classifying, and mapping existing subsurface utilities prior to design and construction, conducted in accordance with ASCE 38-22 (or latest standard).

Quality Levels:

a) Quality Level A (QL-A): Non-destructive excavation (vacuum excavation, hand digging) to expose facilities and determine precise horizontal and vertical position. Typical accuracy: ±1 foot horizontally.

b) Quality Level B (QL-B): Surface geophysical methods (GPR, EM, electromagnetic locating) to determine approximate horizontal position and utility type. Typical accuracy: ±5 feet horizontally.

c) Quality Level D (QL-D): Existing records review and interviews to compile utility information (no field work). Used for preliminary routing only.

Application requirement:

- Minimum QL-B for entire Due Diligence Corridor;
- QL-A required at all potential conflict locations (crossings, near tie-ins, geohazard areas, tight-clearance zones).

2.1.22. **Soft-Dig / Daylighting**

Definition: Non-destructive or minimally destructive excavation methods used to expose and locate existing facilities with precision and without damage.

Methods:

- Vacuum excavation – High-pressure air and water to remove soil; collected soil and fluid are contained and disposed.
- Hand digging – Manual excavation with hand tools.
- Hydro-excavation – High-pressure water spray to excavate and expose.

Requirement: Mandatory within the Excavation Tolerance Zone and at any location where the Excavation Tolerance Zone location is uncertain.

2.1.23. **Construction Execution Plan (CEP)**

A detailed project document that translates encroachment agreement requirements and risk mitigation measures into specific construction procedures, including:

- Construction methods and equipment specifications
- Sequencing and staging
- Requirements for EFR and co-location engineer presence
- Soft-dig and daylighting protocols
- Blasting procedures (if applicable)

- Vibration and pressure reduction criteria (Table 6-2)
- Deviations from standard procedures
- Quality assurance and inspection checklists
- Emergency response procedures

The CEP should be reviewed and approved by both the new pipeline operator and existing facility operator before construction mobilization.

2.1.24. Baseline Survey

Definition: Post-construction survey(s) conducted on the new (and as applicable, existing) pipeline to establish the as-built condition and verify that construction has not caused damage or deviation from design intent.

Types (see Table 7-1):

- ILI (In-Line Inspection) – Internal gauge runs to detect metal loss, dents, deformation.
- CIS (Coating Integrity Survey) – DCVG (Direct Current Voltage Gradient) and similar methods to assess external coating condition and cathodic protection effectiveness.
- AC Survey – AC voltage measurements to verify AC interference mitigation adequacy (for pipelines near HVAC power lines).
- Geohazard Monitoring Baseline – Survey to establish reference points for ongoing deformation monitoring (slope inclinometers, extensometers, GPS).
- ROW Inspection – Field walkdown to visually confirm no damage, proper vent/marker placement, ROW restoration.

Baseline surveys should be completed within 6–12 months of construction completion to allow pipeline pressure stabilization and settlement completion.

2.1.25. Joint Integrity Management Plan (JIMP)

A long-term, collaborative agreement between the new and existing pipeline operators defining:

- Ongoing monitoring and integrity verification activities
- Data sharing protocols and frequency
- Triggers for re-evaluation (e.g., new geohazard evidence, AC/CP system changes)
- Responsibilities for maintenance, repairs, or modifications affecting both facilities
- Contact points and escalation procedures for integrity concerns

The JIMP formalizes the post-construction relationship and commitment to managed co-location for the operational life of the facilities.

2.1.26. **RAGAGEP (Recognized and Generally Accepted Good Engineering Practice)**

The standards, practices, and methodologies that are widely recognized and accepted by the engineering community as appropriate and effective for safe pipeline design, construction, and operations.

Examples relevant to parallel pipelines:

- API Recommended Practice 1172 (Construction Parallel to Existing Pipelines)
- CSA Z662 (Oil and Gas Pipeline Systems)
- AS 2885.1 (Pipelines – Design and Construction)
- IGEM/TD/1 (Buried Pipeline Works)
- ASCE seismic and geohazard guidelines
- NACE/AMPP cathodic protection standards
- PHMSA and FERC regulatory guidance documents

2.1.27. **ALARP (As Low as Reasonably Practicable)**

A risk management principle requiring that residual risks be reduced to levels that are not only acceptable but are as low as can reasonably be achieved through practical and economically feasible measures.

In these Guidelines, ALARP is used to define the target for risk reduction in parallel pipeline projects. Where a baseline design cannot achieve separation distance or other criteria, risk-based mitigation measures should reduce residual risk to ALARP.

2.2. Acronyms and Abbreviations

Acronym	Full Term
AEA	Active Excavation Area
ALARP	As Low As Reasonably Practicable
ASCE	American Society of Civil Engineers
AS	Australian Standards
CEP	Construction Execution Plan
CE	Construction Envelope
CIS	Coating Integrity Survey
CP	Cathodic Protection
CSA	Canadian Standards Association
DCVG	Direct Current Voltage Gradient
DNV GL	Det Norske Veritas GL
EA	Encroachment Area
EFR	Existing Facility Representative
ETZ	Excavation Tolerance Zone
FERC	Federal Energy Regulatory Commission
GPR	Ground Penetrating Radar
HCA	High-Consequence Area
HDD	Horizontal Directional Drilling
HVAC	High-Voltage Alternating Current
IGEM	Institution of Gas Engineers and Managers

ILI	In-Line Inspection
IMP	Interface Management Plan
JIMP	Joint Integrity Management Plan
MCA	Moderate-Consequence Area
NACE	National Association of Corrosion Engineers
OE	Operations Envelope
PHMSA	Pipeline and Hazardous Materials Safety Administration
QL-A	Quality Level A (SUE)
QL-B	Quality Level B (SUE)
RAGAGEP	Recognized and Generally Accepted Good Engineering Practice
ROW	Right-of-Way
RRC	Railroad Commission
SUE	Subsurface Utility Engineering
COPUC	California Public Utilities Commission

3. General Principles and Stakeholder Engagement

3.1. General

3.1.1. General Framework and Joint Responsibility

3.1.1.1. Core Principle: Shared Risk, Shared Responsibility

Damage prevention and interaction risk management in shared corridors are joint responsibilities of all stakeholders, including facility owners/operators, design professionals, one-call centers, constructors, surveyors, regulatory agencies, and land management authorities. Successful parallel pipeline projects depend on recognition that:

a) Parallel construction and long-term co-location create unique interaction risks distinct from isolated pipeline projects.

b) No single party can manage these risks unilaterally; coordinated planning, design, and operations are essential.

c) Transparency and information sharing among all stakeholders reduce uncertainty and enable risk-informed decisions.

d) Continuous improvement through lessons learned and feedback strengthens industry-wide practices.

3.1.1.2. Stakeholder Commitment

Each stakeholder involved in planning, designing, constructing, or operating pipelines in shared corridors should:

a) Recognize and understand the unique interaction risks posed by parallel construction and long-term co-location (mechanical interaction, thermal interaction, electrical interaction, geohazard effects, operational interdependencies).

b) Participate actively in structured stakeholder engagement processes, including:

(i) Early planning and routing meetings (conceptual through final design phases)

(ii) Design review and risk assessment workshops

(iii) Construction readiness reviews (pre-mobilization)

(iv) Periodic post-construction reviews and lessons learned forums

c) Commit to accurate, timely, and complete information sharing, including:

(i) Facility alignment data and markers (via SUE, one-call, direct notification)

(ii) Operating conditions (pressure, temperature, product type, flow rates)

(iii) Design details and integrity history (known defects, prior incidents, maintenance records)

(iv) Cathodic protection system design and performance (test point locations, anode beds, impressed current systems)

(v) AC interference mitigation systems (gradient control mats, bonds, grounding)

(vi) Known geohazards (landslides, flood scour, subsidence, seismic activity)

(vii) Environmental constraints and sensitivities (wetlands, karst terrain, water bodies)

d) Support continuous improvement across the industry through:

(i) Documentation and sharing of lessons learned with industry bodies (INGAA Foundation, API, PRCI)

(ii) Feedback to one-call center operators and damage prevention programs

(iii) Participation in industry forums and research initiatives

(iv) Periodic review and update of these Guidelines to reflect evolving practices and technologies

3.1.1.3. Applicability

This section applies to all parallel pipeline projects, regardless of:

- Pipeline ownership (new and existing operators may be affiliates, competitors, or unrelated entities)
- Product type (natural gas, liquid petroleum, CO_2, water, or other commodities)
- Scale (major transmission lines, distribution pipelines, or gathering systems)
- Corridor configuration (new parallel, existing parallel, or mixed with other utilities)

Exception: For minor parallel segments or short-term construction with demonstrated low interaction risk, operators may apply proportionate (reduced) engagement if documented in the encroachment agreement.

3.2. Stakeholder Engagement Planning and Execution

3.2.1. Requirement for Stakeholder Engagement Plan

The new pipeline operator (project proponent) should develop and implement a Stakeholder Engagement Plan (SEP) that is proportionate to project risk and complexity. The SEP should address all stakeholders identified in Section 3.2.2 and follow principles and timelines outlined in this section.

3.2.2. Stakeholder Categories and Engagement Objectives

3.2.2.1. Primary Stakeholders: Existing Facility Owners and Operators

Who: Owners and operators of all pipelines, utilities, or infrastructure existing or planned within the Encroachment Area and surrounding corridor.

Engagement objectives:

a) Early notification – Inform existing operators of new project routing and parallel construction plans as soon as practicably feasible.

b) Design coordination – Provide detailed design information (alignment, crossing details, CP/AC mitigation) to support existing operator review.

c) Risk assessment – Jointly conduct or review interaction risk assessments (mechanical, thermal, electrical, geohazard).

d) Mitigation planning – Develop mitigation measures (separation, shielding, monitoring) to manage identified risks.

e) Construction coordination – Establish Construction Execution Plan (CEP) incorporating Table 6-1 controls and other safety measures.

f) Ongoing relationship – Formalize long-term coordination via Memoranda of Understanding (MOUs) or Joint Integrity Management Plans (JIMPs).

Engagement timeline:

Phase	Timing	Key Activities
Route Selection & Feasibility	Pre-FERC pre-filing or equivalent permitting gate	Initial identification of parallel segments; reach out to existing operators for alignment data
Preliminary Design	6–12 months before permitting application	Provide preliminary design drawings; discuss interaction concerns; initial risk assessment
Final Design	Concurrent with permitting application	Submit final design; risk assessment report; proposed mitigation measures for acceptance by owner
Pre-Construction	3–6 months before construction mobilization	Finalize CEP; conduct Joint Readiness Review; confirm EFR and communication protocols
Post-Construction	6–12 months after completion	Share baseline survey results; formalize JIMP; schedule ongoing monitoring

3.2.2.2. Regulatory Agencies and Land Management Authorities

Who: Federal, state, provincial, and local regulatory agencies with jurisdiction over pipeline safety, environmental protection, land use, and public welfare, including:

- PHMSA (U.S. Pipeline and Hazardous Materials Safety Administration)
- FERC (Federal Energy Regulatory Commission) for interstate projects
- State pipeline regulatory authorities (RRC in Texas, CPUC in California, etc.)
- Environmental agencies (EPA, state DEP, etc.)
- Land management agencies (BLM, Forest Service, state park authorities)
- Provincial and municipal authorities in international or multi-jurisdictional projects

Engagement objectives:

a) Regulatory expectation setting – Understand agency requirements for parallel pipeline documentation, safety clearances, geohazard assessment.

b) Permit support – Provide technical documentation (risk assessment, mitigation design, alignment maps) to support permit applications.

c) Stakeholder coordination – Facilitate agency input into design decisions affecting public safety or environmental protection.

d) Compliance verification – Confirm that final design and construction execution align with regulatory requirements.

Engagement timeline:

Phase	Key Regulatory Milestones
Pre-filing (FERC projects)	Scoping meetings; issue identification of parallel corridors; request agency input on expectations
Permit application	Formal submission of parallel facility analysis, risk assessment, mitigation measures
Permit review	Agency technical review; coordination with existing operator agencies; conditional approvals
Construction phase	Compliance inspections; incident reporting; post-construction certification
Operations phase	Annual reporting on integrity management; notification of significant changes or incidents

3.2.2.3. Landowners and Communities

Who: Private landowners whose property is traversed by parallel pipelines; residents in communities adjacent to parallel corridors; indigenous peoples and tribal governments with treaty rights or cultural interests.

Engagement objectives:

a) Project transparency – Explain the new pipeline project, parallel construction activities, and safety measures in clear, non-technical language.

b) Access and coordination – Notify of pipeline construction activities on or near property; coordinate access, schedule, and restoration.

c) Safety and emergency response – Provide emergency contact information; explain emergency response procedures; establish communication protocols.

d) Environmental stewardship – Explain environmental protections during construction and operations; commit to restoration and ongoing monitoring.

e) Grievance resolution – Establish mechanism for addressing landowner concerns or complaints.

Engagement timeline:

Phase	**Community Engagement Activities**
Routing & Design	Open house meetings; fact sheets on parallel pipelines; individual outreach to directly affected landowners
Pre-Construction	Construction schedule briefing; access agreements; emergency contact updates
Construction	Weekly progress updates; incident notification; immediate response to complaints
Post-Construction	Restoration completion walk-through; handover of project information; long-term contact for ongoing issues

3.2.2.4. Other Corridor Users: Electric Utilities, Rail, Road, and Telecom

Who: Operators of power lines (AC and DC), railways, highways, telecommunications, water/sewer systems, and other utilities sharing or planned to share the corridor.

Engagement objectives:

a) AC interference assessment – For parallel power lines (transmission or distribution), conduct AC interference modeling and agree on mitigation measures (gradient control mats, bonds, grounding).

b) Physical coordination – Confirm crossing designs, horizontal/vertical clearances, and potential interactions from thermal expansion or vibration.

c) Emergency response – Share emergency contact information; establish mutual aid procedures in case of utility failure.

d) Long-term monitoring – Coordinate monitoring programs to avoid conflicts and share data where beneficial.

Engagement timeline:

Utility Type	Key Coordination Points
AC Power Line	Preliminary: AC field assessment; Final: Detailed mitigation design; Construction: Voltage monitoring; Post-Construction: Baseline AC survey
Railway/Highway	Preliminary: Crossing feasibility; Final: Detailed crossing design with load analysis; Construction: Coordination of crossing work
Telecommunications	Preliminary: Route confirmation; Final: Crossing design; Construction: Protection during crossing
Water/Sewer	Preliminary: Location confirmation; Final: Crossing design (materials, separation); Construction: Coordination of crossing

3.2.3. Stakeholder Engagement Plan Contents

The Stakeholder Engagement Plan should include the following elements:

3.2.3.1. Executive Summary and Project Overview

a) Project description – New pipeline route, length, diameter, product, design pressure, expected operation date

b) Parallel facility identification – All known existing or planned parallel facilities with names, operators, and corridor segments affected

c) Interaction risks overview – High-level summary of identified risks (mechanical, thermal, electrical, geohazard) and proposed management approach

d) Engagement approach – Proportionate to project complexity and risk; phased engagement from early planning through post-construction

3.2.3.2. Stakeholder Identification and Analysis

a) Primary stakeholders (Section 3.2.2.1) – Comprehensive list of existing facility operators with:

(i) Name, address, and emergency contact information

(ii) Facility type, diameter, product, operating pressure

(iii) Known issues or constraints (age, condition, prior incidents)

b) Regulatory agencies (Section 3.2.2.2) – Federal, state, local authorities with jurisdiction and expected review/approval roles

c) Landowners and communities (Section 3.2.2.3) – Geographic areas of project impact; identification of directly affected parcels; community liaisons or tribal contacts

d) Other corridor users (Section 3.2.2.4) – Power lines, railways, utilities; AC interference risk assessment for power lines

3.2.3.3. Engagement Strategy and Timeline

a) Phase-gated approach (routing, design, permitting, construction, post-construction)

b) Engagement methods for each stakeholder group:

(i) One-on-one meetings with existing operators and agencies (highest importance)

(ii) Workshops or technical review meetings for multi-party coordination

(iii) Public open houses for community engagement

(iv) Email and phone communication for routine updates

(v) One-call center notification per applicable damage prevention programs

c) Communication schedule – Specific dates and milestones for each engagement activity.

d) Responsible parties – Who will conduct each engagement activity (project manager, engineer, community liaison)?

e) Contingency and escalation – How will conflicting stakeholder interests be resolved?

3.2.3.4. Information Sharing Framework

a) Types of information to be shared (per Section 3.1.2 c):

(i) Alignment data and SUE results

(ii) Design drawings and specifications

(iii) Risk assessment and mitigation design reports

(iv) Construction plans and schedules

(v) Post-construction survey results

b) Confidentiality and security – How sensitive information (security details, operator-specific technical data) will be protected.

c) Mechanisms for information exchange – Secure portals, email distribution, physical meetings, printed materials.

d) Feedback channels – How stakeholders can raise questions, concerns, or suggestions.

3.2.3.5. Conflict Resolution and Escalation

a) Dispute resolution process – Multi-step escalation:

(i) Technical discussion – Project engineer and existing operator engineer collaborate on solution.

(ii) Project management review – Project managers of both operators attempt resolution.

(iii) Executive escalation – Directors or VPs of both operators make final decision.

(iv) Third-party mediation (if needed) – Neutral mediator or arbitration per encroachment agreement.

b) Timeline for resolution – Target response time for stakeholder concerns (e.g., 5 business days for acknowledgment, 15 days for proposed resolution).

c) Documentation – Record of concerns raised, discussions held, and resolutions reached.

3.2.3.6. Post-Project Review and Lessons Learned

a) Post-Construction Review Meeting (Section 7.5.1) – Structured meeting within 6 months of completion to assess project execution against SEP.

b) Lessons learned documentation – What worked? What could be improved? How will findings be shared with industry?

c) Feedback to INGAA Foundation or industry bodies – Commitment to periodic sharing of lessons learned to support Guideline refinement.

3.2.4. Engagement with Existing Pipeline Operators

3.2.4.1. Early Notification and Initial Engagement

Timing: As soon as parallel routing is identified at conceptual level, and no later than FERC pre-filing or equivalent regulatory pre-filing (e.g., 18–24 months before construction).

Content of initial notification:

a) Project overview – Project name, proponent, timeline, pipeline specifications

b) Parallel segment identification – Geographic extent of parallel routing; map showing both pipelines

c) Preliminary interaction risk assessment – High-level summary of potential mechanical, thermal, electrical, or geohazard interactions

d) Request for baseline information – Ask existing operator to provide:

(i) Facility alignment (current survey data or GIS data)

(ii) Facility specifications (diameter, wall thickness, material grade, design pressure, age)

(iii) Operating conditions (normal and maximum operating pressure, product type, temperature range)

(iv) Known defects or prior incidents (corrosion history, prior damage)

(v) Cathodic protection system details (anode bed locations, test points, impressed current rectifier specifications)

(vi) Any environmental or geohazard concerns

e) Proposed next steps – Schedule for design review meetings, risk assessment, coordination meetings.

Written notification (email or letter) followed by phone call to confirm receipt and arrange meeting.

3.2.4.2. Design Review Meetings

Frequency: Minimum of two formal design review meetings.

Preliminary Design Review (concurrent with or after preliminary design phase) – Topics:

a) Refined alignment and separation distances (comparison to Section 5.0 guidelines)

b) Identified crossings and parallel segments

c) Preliminary interaction risk assessment results

d) Proposed mitigation measures (separation, shielding, monitoring)

e) Special site constraints (geohazards, environmental, existing infrastructure)

Final Design Review (concurrent with or before permit application) – Topics:

a) Final design drawings and specifications

b) Final risk assessment and engineering analyses

c) Detailed mitigation design (CP/AC systems, crossing details)

d) Proposed Construction Execution Plan (CEP) outline

e) Regulatory status and expected approval timeline

f) Sign-off and approval of design by existing operator representative

Attendees: Project engineer, design consultant, new pipeline operator PM, existing operator representative (engineer and/or operations manager), co-location engineer (if assigned).

Documentation: Meeting minutes, action items, distribution to all attendees.

3.2.4.3. Regulatory Pre-Filing Coordination

For FERC-jurisdictional projects, rules require notification of affected landowners and operators. Early engagement with existing pipeline operators is expected and demonstrated through:

a) Pre-filing notification letters – Formal notice of proposed project and request for comments.

b) Meetings with existing operators – Documented meetings addressing their concerns and design modifications.

c) Incorporation of feedback – Design changes or mitigation measures adopted based on existing operator input.

d) Reference in FERC application – FERC filing should include summary of stakeholder coordination, particularly with existing facility operators.

Regulatory expectation: FERC and state agencies increasingly require parallel facility assessments and coordination documentation as part of permit applications.

3.2.4.4. Formalization via Encroachment Agreement

Upon completion of design and regulatory approval, a formal Encroachment Agreement (or equivalent contract) should be executed between new and existing operators. This agreement should:

a) Confirm the roles and responsibilities defined in Section 8.0 (Governance)

b) Specify the design and mitigation measures approved during design review

c) Define construction controls and EFR assignment (per Section 6.0)

d) Establish cost allocation for shared mitigation or monitoring

e) Document liability and insurance requirements

f) Commit to ongoing coordination via JIMP (Section 7.4)

4. Preconstruction

4.1. Route Due Diligence and Corridor Definition

4.1.1. Core Principle: Early, Structured Preconstruction Planning

Preconstruction activities should be deliberate, documented, and proportionate to the risk and complexity of the proposed parallel pipeline project. The objective of preconstruction is to:

a) Establish a robust understanding of existing infrastructure and environmental constraints within and near the proposed route.

b) Identify, characterize, and document interaction risks (mechanical, thermal, electrical, geohazard, and operational).

c) Define corridor limits and Encroachment Areas to support risk assessment, design, and encroachment agreements.

d) Formalize a shared governance framework between the new pipeline operator and existing facility operator(s) prior to construction mobilization.

4.1.2. Due Diligence Corridor – Definition and Scope

4.1.2.1. As part of initial route selection, the new pipeline operator should define a Due Diligence Corridor encompassing all existing facilities that could be affected by the new pipeline construction or operation.

4.1.2.2. Within the Due Diligence Corridor, the new pipeline operator should perform due diligence to identify, at a minimum:

a) All underground and adjacent aboveground structures, including but not limited to:

(i) Transmission and distribution pipelines (gas and liquids)

(ii) High-pressure or high-voltage utilities (electric transmission and distribution, high-pressure water or slurry pipelines)

(iii) Other utilities (sewer, water, telecommunication, fiber optic, cable, drainage systems)

(iv) Civil infrastructure (railways, roads, bridges, culverts, retaining structures)

(v) Major industrial facilities and associated buried infrastructure

b) Service characterization of each identified facility, including:

(i) Service type (pipeline – oil, gas, CO_2, water; electric power line; sewer; water; telecommunication; cable; other)

(ii) Size (diameter or equivalent physical dimension)

(iii) Materials of construction (steel, plastic, composite, concrete, other)

(iv) Status of service (active, idle, out-of-service, or abandoned)

(v) Operating pressure or voltage and typical operating range

(vi) Known integrity or condition issues (where available from public or shared information)

4.1.2.3. The Due Diligence Corridor width should be:

a) Centered on the preliminary centerline of the proposed pipeline; and

b) Adjusted based on site-specific conditions, including:

(i) Existence of wetlands and environmentally sensitive areas

(ii) Vegetative cover and land use (forested, agricultural, urban, industrial)

(iii) Topography (slopes, gullies, ridges, embankments)

(iv) Geology and soil stratigraphy (rock outcrops, soft soils, karst)

(v) Pipe diameter and design operating conditions of the new pipeline

(vi) Required construction work area (ROW width, temporary workspace needs)

(vii) Known or suspected geohazards (landslides, fault zones, subsidence, scour-prone watercourses)

4.1.2.4. The new pipeline operator should document the basis for the selected Due Diligence Corridor width and any adjustments made during route refinement.

4.1.3. Due Diligence Corridor Data Requirements

The following minimum data should be collected, evaluated, and documented for all relevant facilities within the Due Diligence Corridor:

4.1.3.1. Location data:

a) Horizontal and vertical position (coordinates, depth of cover where available)

b) Accuracy class (per ASCE 38 or equivalent)

c) Relationship to proposed pipeline centerline (parallel length, crossing locations, offsets)

4.1.3.2. Facility attributes:

a) Diameter, wall thickness, grade/material, coating type (for pipelines)

b) Voltage, phase configuration, structure type (for electric lines)

c) Pipe material, joint type, pressure class (for water/sewer)

d) Cable count, type, and burial depth (for telecom/fiber/cable)

4.1.3.3. Operational characteristics:

a) Normal and maximum operating pressures (MOP/MAOP) or voltages

b) Temperature profiles where relevant (hot lines, chilled lines)

c) Flow direction and variability

d) Intermittent or batch service characteristics

4.1.3.4. Integrity and incident history (if available):

a) Known incidents (third-party damage, corrosion, fatigue, geohazard-related failures)

b) Ongoing or planned integrity programs

c) Known constraints or sensitivities (e.g., low safety margin, old vintage)

4.1.4. Sample Due Diligence Corridor Data Table

Table 4-1 Example Due Diligence Corridor Facility Inventory

ID	F-01	F-02	F-03	F-04
Facility Type	Gas transmission pipeline	HV AC line	Fiber optic cable	Water main
Owner/Operator	Operator A	Utility B	Telecom C	City D
Service	Sweet gas	230 kV	Data	Potable water
Diameter / Size	30 in	N/A	N/A	24 in
Material	X70 steel	Overhead	Cable	Ductile iron
Status	Active	Active	Active	Active
Pressure/Voltage	1,000 psig	230 kV	N/A	150 psig
Distance from Proposed CL	25 ft (parallel, 2 km)	60 ft (parallel, 1.5 km)	Crossing at MP 12.4	Crossing at MP 8.1
Notes	CP system, HCA segment	AC interference risk	Shallow burial (0.7 m)	Critical city supply

4.2. Multi-Domain Risk Assessment for Parallel Corridors

4.2.1. Requirement for Documented Risk Assessment

4.2.1.1. For all projects involving Parallel Construction (as defined in Section 2.0), the new pipeline operator, in collaboration with existing facility owner(s), should perform a documented, multi-domain risk assessment covering at least the following domains:

a) Mechanical interaction and construction damage

b) Thermal/fire interaction

c) AC interference and cathodic protection (CP) compatibility

d) Geotechnical and seismic hazards

e) Operational and organizational (interface) risks

4.2.1.2. The level of detail and formality of the risk assessment should be proportionate to corridor criticality and complexity considering:

a) Presence of High Consequence Areas (HCAs) and Moderate Consequence Areas (MCAs)

b) Extent and duration of parallelism

c) Product type and operating conditions of both new and existing facilities

d) Complexity of geohazard environment (steep slopes, seismic zones, floodplains, etc.)

e) AC power line co-location

4.2.1.3. The risk assessment may range from:

a) A qualitative assessment (structured expert judgment, risk ranking) for low to moderate complexity corridors; to

b) A semi-quantitative assessment (scoring-based methods with calibrated weighting); to

c) A full Quantitative Risk Assessment (QRA) where warranted by corridor criticality and regulatory expectations (e.g., extended parallelism in HCAs/MCAs).

4.2.1.4. The risk assessment should reference methodologies consistent with:

a) API RP 1172 – Construction parallel to existing underground transmission pipelines

b) CSA Z662 – Oil and gas pipeline systems (including Annex O for geohazards)

c) AS 2885.1 – Pipelines – Gas and liquid petroleum, Part 1: Design and construction

d) Applicable national or regional guidelines and regulations

4.2.2. Minimum Content of Multi-Domain Risk Assessment

The documented risk assessment should, at minimum, include the following elements:

4.2.2.1. Scope and study boundary:

a) Description of the corridor and facilities included in the assessment

b) Definition of parallel segments and crossings

c) Time horizon (construction phase only, or construction and operations)

4.2.2.2. Hazard identification:

a) Identification of potential hazards in each domain (mechanical, thermal, electrical, geohazard, operational/organizational)

b) Consideration of initiating events (e.g., excavation equipment strikes, blasting, landslides, AC faults, operational errors)

c) Use of structured methods (HAZID, What-if, checklists) where appropriate

4.2.2.3. Consequence analysis:

a) Qualitative or quantitative assessment of potential consequences to:

(i) Existing pipelines and facilities

(ii) New pipeline

(iii) Public safety and environment

(iv) Operations continuity and critical services

4.2.2.4. Likelihood assessment:

a) Qualitative likelihood categories (e.g., rare, unlikely, possible, likely, almost certain) or quantitative frequencies based on available data

b) Consideration of historical data for similar interactions (if available)

c) Incorporation of geohazard recurrence intervals where relevant

4.2.2.5. Risk evaluation and ranking:

a) Development of a risk matrix or equivalent tool to rank scenarios

b) Identification of high-risk scenarios requiring mitigation

c) Distinction between construction-phase and operations-phase risks

4.2.2.6. Mitigation strategy and risk reduction measures:

a) Identification of engineering and procedural controls required to reduce risks to ALARP (as low as reasonably practicable) or equivalent standard.

b) Linkage of mitigation measures to design decisions, construction controls (Section 6.0), encroachment agreements (Section 4.4), and ongoing monitoring (Section 7.0).

c) Specification of responsibilities (new operator, existing operator, contractor, others) for implementing each mitigation.

4.2.2.7. Documentation and approval:

a) Summary report capturing methods, data sources, assumptions, and conclusions

b) Review and sign-off by:

(i) New operator's responsible engineer

(ii) Existing operator's designated technical representative (where practicable)

(iii) Co-location engineer of record (where appointed)

c) Retention of risk assessment documentation for the life of the facilities

4.2.3. Example Multi-Domain Risk Assessment Summary Table

Table 4-2 Example Multi-Domain Interaction Risk Summary

Hazard Domain	Example Scenario	Likelihood (Qualitative)	Consequence (Qualitative)	Overall Risk Level	Key Mitigations
Mechanical	Excavator contact with existing gas pipeline during trenching for new line	Possible	Major	High	Table 6-1 AEA controls; soft-dig; EFR presence; depth validation
Thermal/Fire	Loss of containment on new liquids pipeline causing fire near existing gas line	Unlikely	Catastrophic	High	Separation distance; fire protection plan; isolation valves; joint emergency planning
AC/CP	Induced AC on new pipeline from parallel 230 kV line	Likely	Moderate	Medium	Detailed AC modeling; gradient control mats; decoupling; ongoing AC monitoring
Geohazard	Slope instability affecting both pipelines	Possible	Major	High	Geohazard assessment; alignment optimization; strain-based design; monitoring
Operational / Organizational	Miscommunication on shutdown window for existing line during hot work	Possible	Major	Medium	Interface Management Plan; clear roles; checklists; permit-to-work system

4.3. Planning and Design Review Meetings

4.3.1. Designated Contacts and Meeting Objectives

4.3.1.1. The new pipeline operator should contact the operator of each existing facility within the Due Diligence Corridor and arrange a Planning and Design Review Meeting.

4.3.1.2. The respective organizations should establish single points of contact, referred to as

Designated Contacts, who are responsible for:

a) Coordinating planning and design communications between organizations

b) Ensuring timely information exchange and document review

c) Facilitating escalation and issue resolution when required

4.3.1.3. The intent of the Planning and Design Review Meeting is to:

a) Exchange key information about existing facilities and the proposed new facilities.

b) Work through and agree upon respective work processes and procedures for design and construction.

c) Establish clear lines of communication and decision-making authority.

d) Discuss any other details needed to assure that the new facility may be constructed safely and efficiently while simultaneously protecting the existing facility(ies) from damage.

e) Identify and document any constraints, concerns, or data gaps.

4.3.1.4. The meeting should address, at a minimum, the following topics:

a) Placement of the ROW within the broader corridor

b) Location of the new pipeline within the ROW (relative to existing facilities)

c) Types of easements (exclusive, shared, open and undefined) and implications for access, maintenance, and future work

d) Construction methods and practices, including:

(i) Trenching, boring, HDD, or other crossing methods

(ii) Use of heavy equipment and haul routes

(iii) Blasting requirements and limits (see Section 4.6)

e) Unique landscape, terrain, or environmental situations (wetlands, steep slopes, sensitive habitats)

f) Separation distances, including:

(i) Horizontal and vertical separation targets and constraints

(ii) Encroachment Area and Construction Envelope (CE/OE) limits

g) Ground disturbance timing and sequencing relative to existing facility operations

h) Requirements for presence of Existing Facility Representative (EFR) and/or co-location engineer during critical activities

4.3.1.5. The contact initiating the Planning and Design Review Meeting should be made as early as practicable in the routing process and no later than:

a) The filing of the request to begin the FERC Pre-filing Process for FERC-jurisdictional projects; or

b) Equivalent early permitting milestone for non-FERC projects.

4.3.1.6. A suggested Planning and Design Review Meeting Agenda is provided in Attachment A and may be adapted based on project specifics.

4.3.2. Sample Planning and Design Review Meeting Checklist

Table 4-3 Planning and Design Review Meeting Checklist (Excerpt)

Item	Topic	Completed? (Y/N)	Notes/Actions
1	Due Diligence Corridor definition and inventory reviewed		
2	Preliminary alignment and separation distances presented		
3	Encroachment Area and CE/OE limits discussed		
4	Easement types and access rights clarified		
5	Construction methods and AEA controls (Table 6-1) reviewed		
6	Blasting requirements and initial plan (Section 4.6) discussed		
7	AC/CP interference screening results (Section 4.10) presented		
8	Geohazard screening results (Section 4.11) presented		
9	Roles, responsibilities, and Designated Contacts confirmed		
10	Next steps, action items, and schedule agreed		

4.4. Subsurface Utility Engineering (SUE) and Facility Location

4.4.1. SUE Quality Levels within the Due Diligence Corridor

4.4.1.1. Subsurface Utility Engineering (SUE) should be carried out within the Due Diligence Corridor in accordance with ASCE 38-22 (or latest) or an equivalent standard.

4.4.1.2. At a minimum, the following SUE quality levels should be applied:

a) Quality Level B (QL-B) or better:

(i) Adopted for the entire Due Diligence Corridor to determine the horizontal position of existing subsurface utilities using appropriate surface geophysical methods.

(ii) Used to develop a baseline subsurface utility map supporting route optimization and risk assessment.

b) Quality Level A (QL-A) – Daylighting / soft-dig:

(i) Applied at all potential conflict locations, including but not limited to:

- Crossings (pipeline-pipeline, pipeline-utility)
- Near tie-ins and valve sites
- Geohazard areas where differential movement may be expected
- Locations where construction tolerances are tight or separation is limited

(ii) Achieved using non-destructive or minimally destructive excavation methods (vacuum excavation, hand digging) to expose facilities and determine precise horizontal and vertical position.

4.4.1.3. The new pipeline operator should document:

a) SUE scope and methods used

b) Quality level achieved at each location

c) Any limitations or uncertainties in the utility data

4.4.2. Coordination of SUE with Existing Facility Operators

4.4.2.1. SUE activities should be coordinated with existing facility operators to:

a) Confirm alignment data and reconcile discrepancies between records and field observations

b) Validate depth of cover and spatial relationships at critical locations

c) Identify any undocumented or abandoned facilities

4.4.2.2. Where discrepancies between records and SUE findings occur, the new pipeline operator and existing facility operator should:

a) Jointly review field results

b) Agree on the interpreted facility location and depth for design purposes

c) Adjust risk assessment and mitigation measures as necessary

4.5. Encroachment Agreements

4.5.1. Purpose and Timing

4.5.1.1. For new pipelines located within the Encroachment Area of existing facilities, encroachment agreements between the new pipeline operator and existing facility operator(s) should be executed before construction mobilization.

4.5.1.2. Encroachment agreements should formalize:

a) Encroachment Area and operational envelope definitions

b) Agreed separation distances and alignment constraints

c) Construction-phase controls and responsibilities

d) Post-construction integrity activities and data-sharing

e) Interface Management Plan (IMP) roles and decision rights

f) Cost allocation and liability framework

4.5.2. Minimum Content of Encroachment Agreements

At a minimum, encroachment agreements should:

4.5.2.1. Define Encroachment Area and Separation Distances

a) Define Encroachment Area, Construction Envelope (CE), and Operations Envelope (OE) limits for each segment

b) Specify target separation distances (horizontal and vertical) by segment, reflecting:

(i) Risk assessment outcomes (Section 4.2)

(ii) Site constraints (ROW width, terrain, environmental restrictions)

(iii) Regulatory or standard-based minimums (where applicable)

4.5.2.2. Address Cathodic Protection and AC Interference

a) Identify all existing cathodic protection (CP) systems and AC interference mitigation systems, including:

(i) Type of CP system (impressed current, sacrificial anodes)

(ii) Locations of groundbeds, distributed anodes, and test stations

(iii) Known interference issues or sensitivity to interference

b) Define requirements and responsibilities for:

(i) AC interference and CP compatibility modeling (e.g., CDEGS or equivalent)

(ii) Development of a conceptual mitigation strategy at design stage

(iii) Implementation, ownership, and maintenance of mitigation measures (bonds, grounding, gradient control mats, decouplers)

(iv) Sharing of CP and AC monitoring data during construction and operations

4.5.2.3. Define Construction-Phase Controls

a) Specify requirements for:

(i) Presence of an Existing Facility Representative (EFR) during construction within the Active Excavation Area (AEA)

(ii) Soft-dig or non-destructive excavation near existing facilities

(iii) Vibration limits, pressure reduction criteria, and blasting controls (see Sections 4.6 and 6.0, Table 6-1 and Table 6-2)

(iv) Monitoring and communication protocols during ground disturbance

b) Reference applicable controls from Table 6-1: Mandatory Construction Controls within the AEA and related tables

4.5.2.4. Set Expectations for Geohazard and Seismic Assessments

a) Identify segments where geohazard or seismic risk is present

b) Define expectations for geohazard screening and detailed assessment (see Section

4.11)

c) Agree on responsibilities for implementing geohazard-related risk controls affecting both new and existing facilities

4.5.2.5. Define Post-Construction Integrity Activities

a) Establish baseline surveys (e.g., ILI, CIS, AC surveys, geohazard monitoring) to be completed post-construction (see Section 7.2 and Table 7-1)

b) Define monitoring cadence and triggers for re-evaluation (see Section 7.4 and Table 7-2)

c) Specify data-sharing commitments and mechanisms (e.g., periodic summary reports, joint review meetings)

4.5.2.6. Establish a Formal Interface Management Plan (IMP)

Encroachment agreements should establish or reference a formal Interface Management Plan (IMP) that defines:

a) Key roles (e.g., co-location engineer of record, project manager, field coordinators, EFR)

b) Decision rights and approval authorities for:

(i) Design changes affecting separation or alignment

(ii) Construction deviations from CEP or controls

(iii) AC/CP mitigation adjustments

(iv) Geohazard response measures

c) Communication pathways and escalation protocols (routine communications, incident notifications, emergency contacts)

d) Deviation management process (see Section 8.0):

(i) Deviation identification and documentation

(ii) Risk evaluation and approval workflow

(iii) Recording in deviation register

4.5.2.7. Cathodic Protection Facilities Coordination

The encroachment agreement should specifically address cathodic protection facilities, including coordination between parties on:

a) Existing and new CP systems;

b) Location and capacity of concentrated groundbeds and distributed anodes

c) Test station locations and monitoring responsibilities

d) Potential and observed interference between systems

e) Planned modifications (if any) to support safe co-location

4.5.3. Example Encroachment Agreement Content Checklist

Table 4-4 Encroachment Agreement Checklist (Excerpt)

Item	Topic	Included? (Y/N)	Notes
1	Encroachment Area and CE/OE limits by segment		
2	Target separation distances (horizontal/vertical)		
3	CP system descriptions and locations of groundbeds/anodes		
4	AC interference modeling requirements and responsibilities		
5	Construction-phase controls (EFR presence, soft-dig, vibration limits, pressure reduction criteria, blasting controls)		
6	Geohazard and seismic assessment expectations		
7	Post-construction baseline surveys (types, timing)		
8	Monitoring cadence and data-sharing commitments		
9	Interface Management Plan roles and decision rights		
10	Deviation management process and register		
11	Cost allocation and liability provisions		

4.6. Blasting Assessment and Blasting Plan

4.6.1. Identification of Blasting Areas

4.6.1.1. The new pipeline operator should identify areas along the proposed route where blasting will be used within 300 ft (90 m) of any existing facilities.

4.6.1.2. Blasting may be required for:

a) Rock excavation for trenching or HDD entry/exit pits

b) Foundation excavation for major structures

c) Other construction activities involving explosives

4.6.2. Blasting Plan Requirements

4.6.2.1. A Blasting Plan should be developed and agreed to by both the new pipeline operator and each affected existing facility operator before any blasting occurs in proximity to their facilities.

4.6.2.2. The Blasting Plan should include, at a minimum:

a) Description of blasting locations and proximity to existing facilities

b) Geotechnical characterization of the blasting area (rock type, structure, discontinuities)

c) Maximum allowable vibration levels at existing facilities, referencing Table 6-2: Vibration and Blasting Control Parameters

d) Blast design parameters (charge size, delay timing, burden and spacing)

e) Monitoring plan (seismograph locations, recording parameters, trigger levels)

f) Communication and notification procedures:

(i) Advance notification timelines to existing operators

(ii) Real-time communication during blasting operations

g) Contingency actions if measured vibration levels exceed agreed criteria

h) Roles and responsibilities (blasting contractor, new operator representative, EFR)

i) Post-blast inspection requirements for existing facilities

4.6.2.3. The Blasting Plan should be reviewed by a qualified blasting engineer and, where required by regulation or company standard, by a geotechnical engineer and the existing operator's designated technical representative.

4.7. Corridor Survey and One-Call Coordination

4.7.1. Pre-Survey Notification and One-Call Design Tickets

4.7.1.1. In preparation for conducting a corridor survey (e.g., centerline staking, topographic survey, environmental survey), the new pipeline operator should:

a) Contact the existing facility operator directly and/or

b) Use the one-call system where a design ticket is available

4.7.1.2. The one-call request should include specific starting and ending points using GPS coordinates sufficient to ensure that any Encroachment Areas and relevant facilities are included.

4.7.1.3. Survey activities should not commence until:

a) Required one-call notifications have been made; and

b) Any applicable waiting periods have elapsed per regulatory or one-call program requirements.

4.7.2. Positive Response and Facility Marking

4.7.2.1. In addition to state requirements for one-call center notification, the existing facility Designated Contact should notify the new pipeline Designated Contact that either:

a) There is no conflict within the requested survey area; or

b) The line will be marked (referred to as "positive response"), consistent with CGA Best Practices – Locating and Marking, Practice 4-9.

4.7.2.2. The existing facility operator should, or by delegation, cause its facilities to be located and marked using appropriate line location methods that will assure the accurate placement of the markers, taking into account:

a) Facility depth and material

b) Electromagnetic and other geophysical detection limitations

c) Environmental and site conditions

4.7.2.3. The new pipeline operator should:

a) Verify that markings are consistent with the expected facility locations

b) Raise discrepancies promptly with the existing operator and, if necessary, perform additional SUE or daylighting (see Section 4.4)

4.8. AC and CP Interference Screening

4.8.1. Screening Requirements

4.8.1.1. Where parallel or crossing segments occur within the Operations Envelope of high-voltage AC (HVAC) transmission lines or other pipelines with active CP systems, the new pipeline operator should perform AC and CP interference screening during preconstruction.

4.8.1.2. Screening should consider, at minimum:

a) HVAC line current loading and configuration (voltage, circuit number, phasing)

b) Pipeline separation distance and collocation length

c) Soil resistivity and stratigraphy

d) Crossing angle and frequency of crossings

4.8.1.3. Where screening indicates medium or high severity (e.g., per INGAA/DNV GL severity matrix or equivalent method):

a) Detailed AC interference modeling (e.g., CDEGS or equivalent) should be performed at the design stage;

b) A conceptual mitigation strategy should be developed and documented; and

c) The outcomes should be reflected in encroachment agreements (Section 4.5) and in the Construction Execution Plan (Section 6.0).

4.9. Geohazard Screening and Detailed Assessment

4.9.1. Geohazard Screening Requirements

4.9.1.1. In areas of known or potential geohazards (e.g., landslides, active faults, liquefaction-prone deposits, subsidence, sinkholes, riverine scour), the routing and preconstruction assessment should include a geohazard screening.

4.9.1.2. Geohazard screening should:

a) Utilize desktop information (geologic maps, aerial imagery, LiDAR, historical records) and initial field reconnaissance.

b) Identify potential hazard zones affecting either or both the new and existing facilities.

c) Categorize hazard severity (e.g., low, medium, high) and likelihood.

4.9.1.3. Where screening indicates medium or high hazard, a detailed geohazard assessment should be performed following appropriate guidelines (e.g., CSA Z662 Annex O, ASCE seismic and geohazard guidelines, or equivalent national standards).

4.9.2. Parallel Alignment Justification and Controls in Geohazard Areas

4.9.2.1. Parallel alignment in geohazard-prone areas should be explicitly justified in the routing and risk assessment documentation.

4.9.2.2. Risk controls should be identified and evaluated early, which may include:

a) Alignment offsets to increase separation between pipelines and/or avoid the most active hazard zones

b) Strain-based design or enhanced design criteria for segments subject to potential ground movement

c) Differential burial strategies or special trench/embankment designs

d) Ground improvement measures (e.g., drainage, buttressing, soil stabilization)

e) Enhanced monitoring (deformation monitoring, inclinometers, remote sensing)

f) Operational controls (reduced pressure, shutdown triggers) tied to geohazard monitoring

4.9.2.3. Geohazard-related controls affecting multiple facilities should be incorporated into:

a) Encroachment agreements (Section 4.5)

b) Joint Integrity Management Plans (JIMPs) and monitoring programs (Section 7.4)

4.10. Corridor Marking

4.10.1. Marker Placement in the Due Diligence Corridor

4.10.1.1. Markers should be placed in the Due Diligence Corridor at spacing not to exceed:

a) 200 ft (60 m); or

b) Line-of-sight, whichever distance is shorter.

4.10.1.2. Markers should also be placed at all points of inflection (PIs) and at key locations such as:

a) Crossings with existing facilities

b) Geohazard zones

c) Entry/exit points for HDDs or tunnels

d) Major structures or valve locations

4.10.1.3. Markers should be clearly labeled and differentiated (e.g., survey control, proposed pipeline centerline, Due Diligence Corridor limit) in accordance with project survey standards.

4.11. Ongoing Preconstruction Communication

4.11.1. Regular Communication and Coordination

4.11.1.1. The new pipeline operator should regularly communicate and coordinate with the operators of existing facilities concerning the status of the project for the duration of the preconstruction phase and into construction, consistent with CGA Best Practices – Planning and Design, Practice 2-4.

4.11.1.2. Regular communications should include, as appropriate:

a) Updates on routing and design changes affecting parallel segments

b) Status of permits and regulatory approvals relevant to parallel facilities

c) Planned survey and geotechnical investigation activities near existing facilities

d) Planned SUE and daylighting activities (Section 4.4)

e) Planned blasting activities and Blasting Plan development (Section 4.6)

f) Planned scheduling of construction mobilization and work within the Encroachment Area

4.11.1.3. Communication formats may include:

a) Periodic coordination meetings (in-person or virtual)

b) Written status updates (email summaries, memos)

c) Shared project dashboards or collaboration platforms, subject to confidentiality agreements

4.11.1.4. The Designated Contacts for both the new and existing operators should:

a) Maintain an up-to-date log of key communications and decisions affecting preconstruction coordination.

b) Ensure that agreed changes affecting safety, design, or risk controls are documented and integrated into the design, CEP, encroachment agreements, and IMP.

5. Engineering Design

5.1. General

5.1.1. The engineering design of new pipelines constructed in parallel with existing facilities should address both:

a) the Construction Envelope (CE), where construction activities can affect the safety and integrity of existing facilities; and

b) the Operations Envelope (OE), where long-term interaction mechanisms (mechanical, thermal, electrical, geotechnical) may influence the performance of co-located assets.

5.1.2. Design should be risk-based, integrating:

a) applicable regulations (e.g., 49 CFR Parts 192/195, CSA Z662, AS 2885, IGEM/TD/1);

b) recognized practices (e.g., API RP 1172, INGAA/DNV GL AC interference criteria, NACE/AMPP standards); and

c) project-specific hazard assessments covering mechanical, thermal, electrical/CP, and geohazard risks.

5.1.3. Where default separation distances in this Guideline cannot be achieved, the designer should develop a documented engineering deviation case (see 5.3.5).

5.2. Construction and Operations Envelopes

5.2.1. Construction Envelope (CE)

5.2.1.1. The Construction Envelope consists of the following zones:

a) Encroachment Area (EA): Disturbance within 50 ft (15 m) of the existing facility centerline, or within the existing ROW/easement, whichever is greater.

b) Active Excavation Area (AEA): Edge of disturbance within 25 ft (7.5 m) of the existing facility centerline.

c) Excavation Tolerance Zone (ETZ): Within 2 ft (0.6 m) of the existing facility, or as specified by state/provincial law, whichever is greater.

5.2.1.2. Within the CE, engineering design should define:

a) allowed and prohibited construction methods

b) requirements for Existing Facility Representative (EFR) presence

c) soft-dig and daylighting expectations

d) blasting and vibration limits

e) any temporary operating restrictions (e.g., pressure reduction or shutdown) for existing lines.

5.2.2. Operations Envelope (OE)

5.2.2.1. The Operations Envelope is the corridor within which long-term interactions between facilities must be assessed. It typically extends beyond the CE and is risk-scaled.

5.2.2.2. For design purposes, the OE should be divided into tiers relative to the existing facility centerline:

Table 5-1 Operations Envelope Tiers

Tier	Separation (horizontal)	Typical treatment
OE-1	≤ 10 ft (≤ 3 m)	Detailed interaction modeling required (all domains).
OE-2	> 10 ft to 30 ft (>3–≤9 m)	Screening + targeted modeling based on risk.
OE-3	> 30 ft (> 9 m)	Screening; modeling where special conditions exist.

5.2.2.3. Tier assignment should be used to trigger the level of analysis for:

a) AC induction and CP interference

b) thermal and fire escalation

c) mechanical interaction under rupture or large ground deformation

d) geohazard/seismic coupling

5.3. Separation and Proximity Criteria

5.3.1. Default Separation Distances

5.3.1.1. The following default horizontal separations between parallel transmission pipelines (centerline-to-centerline) are recommended for planning and permitting. They are not substitutes for risk assessment but provide a baseline consistent with contemporary practice and literature.

Table 5-2 Default Horizontal Separations Between Parallel Transmission Pipelines

Corridor / Terrain	Default Separation (ft)	Notes
Rural, benign soils	30	Provides construction access and basic interaction margin.
Congested utility corridor	20	Requires detailed interaction assessment.
Rocky or blasted trench conditions	30–50	Higher risk of stress concentration, blasting.
High consequence / urban corridor	30–65	Consider upper bound where practicable.

5.3.1.2. Where separation < 30 ft between two large-diameter, high-pressure pipelines is proposed, the designer should perform mechanical, thermal, and electrical interaction analyses consistent with 5.4, 5.5, and 5.6 to demonstrate acceptability.

5.3.2. Vertical Separation at Crossings

5.3.2.1. Minimum vertical clearances (edge to edge) between crossing pipelines should be:

a) crossing over: ≥ 1.5 ft;

b) crossing under: ≥ 3.0 ft;

unless a different minimum is required by applicable codes or the host operator, in which case the more stringent applies.

5.3.2.2. For trenchless crossings, the minimum vertical clearance between the drill path and the existing pipeline should be 10 ft, unless a project-specific analysis justifies a lesser distance with enhanced controls.

5.3.3. Separation Tables – Interaction Screening

Table 5-3 provides screening distances for when more detailed interaction modeling is required, based on product mix and separation.

Table 5-3 Screening Distances - Interaction Model

Case	**Separation (ft)**	**Required analyses**
Gas–gas, similar MAOP	≥ 30	Screening only; detailed as warranted.
Gas–liquid (flammable)	15–30	Thermal + mechanical + CP/AC screening.
Gas–liquid (flammable)	< 15	Full mechanical + CFD thermal + AC/CP modeling.
Hydrocarbon–CO_2 or H_2	Any < 30	Full interaction assessment due to novel hazards.

5.3.4. Regulatory Minimum Clearances

5.3.4.1. Under no circumstances should the design violate applicable code minimum clearances, such as:

a) ≥ 12 in (300 mm) separation between gas pipelines and any other underground structure per 49 CFR §192.325, or equivalent national/regional requirements;

b) ≥ 300 mm clearance between buried pipelines and other underground structures per CSA Z662 Clause 4.11 or successor clauses.

5.3.5. Risk-Based Deviation Protocol

5.3.5.1. Where default separations (5.3.1–5.3.3) cannot be met, an Engineering Deviation Case should be prepared including:

a) description of deviation and rationale (e.g., ROW constraint, geohazard avoidance)

b) inputs and assumptions (soil, pressures, products, operating envelopes, corridor users)

c) models and methods used (e.g., FEM for rupture/blast, CFD for thermal, CDEGS/TLM for AC/CP)

d) acceptance criteria (e.g., allowable stress/strain, thermal limits, AC voltage/current density thresholds)

e) mitigation measures to reduce risk to ALARP

f) review and approval, including peer or independent review for HCAs/MCAs, hydrogen/CO_2, or other elevated-risk corridors

5.3.5.2. Deviation cases and associated approvals should be retained as part of the project design dossier and referenced in encroachment agreements.

5.4. Mechanical Interaction and Structural Design

5.4.1. Design Objectives

5.4.1.1. Mechanical design should demonstrate that:

a) construction activities near existing facilities will not impose stresses or displacements that threaten integrity

b) credible rupture, blast, or crater formation in one line will not cause unacceptable damage to adjacent lines, or that mitigation reduces such risk to ALARP.

5.4.2. Construction-Phase Mechanical Interaction

5.4.2.1. For work within the CE, the design should:

a) evaluate loads from construction equipment, stringing, and stockpiling near existing pipelines

b) define maximum allowable equipment weight and crossing configurations over existing facilities;

c) where necessary, specify temporary bridging, matting, or load-distribution structures

5.4.2.2. In rocky or blasted trench segments, design should:

a) assess stress concentrations from rock points or irregular bedding

b) specify bedding materials and thicknesses

c) require inspection of existing pipe exposure and support conditions when adjacent excavation occurs

5.4.3. Rupture, Blast, and Crater Interaction

5.4.3.1. For parallel segments with small separation (< 30 ft) and high-pressure pipelines, the design should consider:

a) soil cratering and ground motion from rupture

b) local bending and ovalization of adjacent lines

c) potential for pipe-on-pipe impact in extreme cases

5.4.3.2. Where existing research (e.g., PRCI, IGEM/TD/1, AS 2885) is applicable, the designer should:

a) use available blast interaction models or FEM

b) define a measurement length and maximum allowable strain for adjacent pipelines under incident loading.

5.4.3.3. Where analyses identify unacceptable risk, options may include:

a) increasing separation where practicable

b) local reinforcement (e.g., sleeves, concrete encasement)

c) pressure reduction on one or both lines

d) design of anti-propagation features (e.g., rupture arrestors) in high-interaction segments

5.4.4. Sample Mechanical Risk Checklist

The following checklist is provided as a design aid:

- Have construction equipment loads over/near existing lines been calculated and checked?
- Is there a requirement for temporary bridges, mats, or reduced equipment weights?
- Are there segments with separation < 30 ft where rupture/blast modeling is required?
- Have rocky/uneven bedding conditions been identified and mitigated?
- Have strain/stress limits for adjacent lines under interaction scenarios been defined?

5.5. Thermal and Fire Interaction Assessment

5.5.1. Screening

5.5.1.1. The designer should perform a thermal/fire interaction screening where any of the following apply:

a) adjacent pipelines transport flammable or combustible products

b) horizontal separation ≤ 30 ft

c) corridor segments in HCAs/MCAs with multi-product lines

d) segments near populated or critical infrastructure

5.5.1.2. If screening identifies credible escalation risk, detailed assessment per 5.5.2–5.5.3 is required.

5.5.2. Analysis

5.5.2.1. Thermal interaction analysis should be performed using CFD and/or transient thermal models consistent with current practice and case studies (e.g., Ruan et al.).

5.5.2.2. Analyses should consider:

a) representative jet and/or pool fire scenarios for each product type

b) wind speed/direction variability

c) duration of uncontrolled release and ignition

d) thermal properties of soil, coatings, and any shields

e) wall temperature evolution and loss of strength in adjacent lines

5.5.2.3. Acceptance criteria should be defined in terms of:

a) maximum allowable wall temperature vs actual operating pressure

b) minimum time-to-failure vs emergency shutdown and depressurization timelines

c) compliance with relevant standards or company criteria for thermal exposure

5.5.3. Mitigation

5.5.3.1. Where analysis indicates inadequate thermal margin, design should evaluate:

a) increased separation where physically feasible

b) thermal shielding solutions (e.g., fire-resistant wraps, barriers, earth berms)

c) enhanced emergency isolation (e.g., remotely actuated valves, optimized ESD location)

d) reduction of inventory or pressure in susceptible segments.

5.5.3.2. Mitigation details (materials, extent, performance requirements) should be documented and incorporated into construction and emergency response plans.

5.5.4. Sample Thermal Interaction Checklist

- Have product types and operating conditions for all parallel lines been catalogued?
- Is separation ≤ 10 m for any flammable-flammable pair?
- Have representative jet/pool fire scenarios been modeled?
- Does time-to-critical temperature exceed emergency isolation time with margin?
- Are shielding or other mitigations specified where needed?

5.6. Interference and Cathodic Protection Compatibility

5.6.1. Screening, Triggers, and Severity

5.6.1.1. Electrical interaction (AC induction, AC corrosion, DC/CP interference) should be screened where:

a) pipelines run parallel to HVAC lines carrying ≥ 1,000 A

b) separation between pipeline and HVAC line is ≤ 100 ft

c) collocation length exceeds 0.5 miles

d) soil resistivity is low or highly variable

e) multiple pipelines with active CP systems share a corridor

5.6.1.2. The screening should apply a severity matrix similar to INGAA/DNV GL criteria, scoring:

- separation distance
- current load
- soil resistivity
- collocation length
- crossing angle.

5.6.2. Modeling

5.6.2.1. Where screening identifies medium/high severity, detailed AC/CP modeling should be performed using suitable tools (e.g., CDEGS, SESShield):

a) compute induced AC voltages and current densities at coating holidays

b) assess touch and step potentials

c) evaluate DC interference between CP systems

5.6.2.2. Design criteria should include, as applicable:

a) touch voltage ≤ 15 Vrms under steady-state and fault conditions

b) AC current density at coating defects within accepted corrosion control limits

c) sufficient CP potentials within design ranges for all affected pipelines

5.6.3. Mitigation and Design Measures

5.6.3.1. Where required by modeling, mitigation may include:

a) gradient control mats or zinc ribbon groundbeds

b) sectional bonding between pipelines

c) decoupling devices for CP/AC separation

d) optimized placement of test stations and monitoring coupons

5.6.3.2. Design should define:

a) ownership and maintenance responsibilities for shared mitigation

b) monitoring plans (locations, parameters, frequencies)

c) commissioning test procedures and acceptance criteria

5.6.4. Documentation Requirements

5.6.4.1. AC/CP design records should include:

a) model inputs and key outputs

b) soil resistivity surveys

c) locations and details of grounding, bonds, and decouplers

d) test station IDs, coordinates, and ownership

e) baseline commissioning measurements and re-verification intervals

5.7. Geohazard and Seismic Considerations

5.7.1. Geohazard Screening and Assessment

5.7.1.1. The design should include geohazard screening for the shared corridor to identify:

a) landslides, debris flows, and slope instabilities

b) river crossings and floodplain erosion/scour

c) subsidence, karst, and collapsible soils

d) frost heave and permafrost

5.7.1.2. Where hazards are identified, detailed assessments should follow recognized guidance (e.g., CSA Z662 Annex O, ASCE seismic/geotechnical guidelines).

5.7.2. Seismic Design

5.7.2.1. In moderate-to-high seismic areas, the design should:

a) perform site-specific seismic hazard analyses for ground motion

b) consider wave propagation, liquefaction, and fault displacement on both existing and new lines

c) evaluate differential movement between parallel lines with differing stiffness, burial depth, and restraint

5.7.2.2. Mitigation may include:

a) strain-based design

b) flexible joints or slip couplings

c) trench improvements (e.g., low-stiffness backfill) to accommodate deformation

d) avoidance or rerouting in the most severe zones.

5.8. Trenchless and Advanced Construction Methods

5.8.1. General

5.8.1.1. Where trenchless or advanced methods (e.g., HDD, micro tunneling) are used in the CE/OE, the design should include:

a) engineered drill path with clearance to existing lines

b) annular pressure management plan

c) frac-out and loss-of-circulation risk assessment

d) monitoring and contingency measures near existing facilities

5.8.2. Minimum Clearances

5.8.2.1. Unless more stringent host-operator criteria apply, minimum clearances for trenchless installations should be:

a) 10 ft vertical between drill path and existing pipeline

b) 5–10 ft horizontal “witness trench” offset for visual confirmation during crossing

5.8.3. Sample Trenchless Design Checklist

- Has a full drill path profile with clearances to all existing utilities been prepared?
- Are minimum vertical and horizontal separations to existing pipelines satisfied or justified?
- Have annular pressure limits and monitoring locations been specified?
- Are frac-out contingency plans aligned with existing operator expectations?

6. Construction Controls and Field Execution

6.1. General

6.1.1. Construction activities within the Construction Envelope (CE) should be planned, executed, and documented to prevent damage to existing facilities and ensure personnel safety.

6.1.2. The new pipeline operator, in coordination with the existing facility operator(s), should develop a Construction Execution Plan (CEP) that incorporates:

a) zone-specific controls (Encroachment Area, Active Excavation Area, Tolerance Zone)

b) roles and responsibilities, including Existing Facility Representative (EFR) assignment

c) communication protocols and escalation procedures

d) permit-to-work and daily authorization procedures

e) vibration/blasting plans where applicable

f) contingency and emergency response plans

g) documentation and deviation management processes

6.1.3. The CEP should be reviewed and approved by both operators prior to mobilization into the Encroachment Area.

6.2. Notification and Scheduling

6.2.1. Pre-Construction Notification

6.2.1.1. The new pipeline operator should provide the existing facility operator with written notification at least 30 days prior to initial ground disturbance within the Encroachment Area.

6.2.1.2. Notification should include:

a) proposed construction schedule with key milestones

b) anticipated start and end dates for work in each segment of the Encroachment Area

c) identification of high-risk activities (blasting, HDD, crossings, AEA work)

d) contact information for field supervision and 24/7 emergency contacts

6.2.2. Weekly Updates and Coordination

6.2.2.1. During active construction in the Encroachment Area, the new pipeline operator should provide the existing facility operator with weekly schedule updates via the Designated Contacts.

6.2.2.2. Updates should identify:

a) upcoming work locations and activities for the following 7–14 days

b) any changes to planned methods or timing

c) status of completed work and any issues encountered

6.2.2.3. The process continues until final restoration and acceptance in the Encroachment Area is complete.

6.2.3. 24-Hour Advance Notice for Active Excavation Area

6.2.3.1. Before commencing ground disturbance in the Active Excavation Area (AEA, ≤25 ft), the new pipeline operator should provide the existing facility operator's Designated Contact with at least 24 hours advance notice.

6.2.3.2. Work should not commence until:

a) the existing operator confirms EFR availability, or

b) the existing operator confirms in writing to proceed without EFR presence (only where pre-agreed and documented in the encroachment agreement).

6.3. Mandatory Construction Controls Within Active Excavation Area (≤25 ft)

6.3.1. General Requirements

6.3.1.1. Within the AEA, the controls specified in Table 6-1 should be implemented unless an engineering risk assessment demonstrates that equivalent or superior controls are in place.

6.3.1.2. Daily communication should occur between the new pipeline construction supervision and the EFR, including:

a) pre-shift briefing on planned activities, locations, and sequence

b) end-of-shift debrief on work completed and any concerns

Table 6-1 Mandatory Construction Controls Within Active Excavation Area (≤25 ft)

Control Measure	Requirement	Trigger Condition	Reference
Existing Facility Representative (EFR	On-site presence whenever ground disturbance occurs	Any ground disturbance in AEA	Section 6.3.2
Soft-Dig / Daylighting	Hydrovac or hand excavation within Tolerance Zone (2 ft)	Approaching within 2 ft of existing facility	Section 6.3.3
Equipment Restrictions	Toothless buckets; side-cutters removed	Mechanical excavation in AEA	Section 6.3.4
Vibration/Blast Monitoring	Per approved plan with project-specific limits	Within 300 ft of blasting; heavy equipment operation in AEA	Section 6.3.6
Physical Barriers	Trench boxes, safety barriers, matted crossings as required	Where exposure, surcharge, or crossing risk exists	Section 6.3.7

6.3.2. Existing Facility Representative (EFR)

6.3.2.1. The existing facility operator should assign a competent EFR for all ground disturbance within the AEA.

6.3.2.2. The EFR should:

a) be present on-site during ground-disturbing activities

b) possess knowledge of the existing facility's design, operation, and integrity requirements

c) have authority to stop work if safety or integrity of the existing facility is at risk

6.3.2.3. Where continuous EFR presence is not feasible (e.g., large linear project with intermittent AEA exposure), the parties may agree on protocols for EFR rotation or remote monitoring, provided equivalent risk control is documented.

6.3.3. Soft-Dig and Daylighting

6.3.3.1. Within the Excavation Tolerance Zone (≤2 ft or state-mandated distance, whichever is greater), only non-mechanical excavation methods should be used to expose the existing facility.

6.3.3.2. Acceptable methods include:

a) hydrovac (vacuum excavation)

b) hand tools (shovels, probes)

c) low-pressure air or water excavation under controlled conditions

6.3.3.3. Mechanical excavation may resume outside the Tolerance Zone once the existing facility is visually confirmed and protected.

6.3.4. Equipment Restrictions

6.3.4.1. Excavation equipment operating within the AEA should have teeth removed or guarded and side-cutters removed (e.g., toothless buckets, smooth-edged trenching equipment).

6.3.4.2. Site-specific equipment plans may be approved by the existing facility operator where alternative controls (e.g., precision guidance systems, operator certification) provide equivalent protection.

6.3.5. Trench Stability and Support

6.3.5.1. Where excavation adjacent to an existing facility may affect soil support, trench stability measures should include:

a) proper sloping, benching, or shoring per OSHA/CSA standards

b) avoidance of undermining existing pipe supports

c) dewatering controls to prevent buoyancy or flotation of existing facilities.

6.3.5.2. Temporary support (e.g., sand bags, timber blocking) should be installed if the existing facility is exposed and unsupported spans exceed safe limits.

6.3.6. Vibration and Blasting Controls

6.3.6.1. Where blasting, pile-driving, or heavy vibratory equipment is used within 300 ft (90 m) of an existing facility (or greater distance if specified by the existing operator or risk assessment), a Vibration and Blasting Plan should be prepared and approved.

6.3.6.2. The plan should include:

a) identification of all existing facilities within the influence zone

b) vibration limits (peak particle velocity, PPV) appropriate to soil conditions and pipe characteristics (see Table 6-2 below)

c) monitoring locations, instrumentation, and real-time alert procedures

d) procedures for temporary pressure reduction or shutdown of existing facilities if limits are approached or exceeded

e) notification and coordination protocols

Table 6-2 Vibration and Blasting Control

Activity	**Trigger Distance**	**Typical Limit (PPV)**	**Monitoring**	**Notes**
Blasting in rock trench	≤ 300 ft (90 m)	2.0 in/s (50 mm/s	Seismograph at existing pipe or nearest accessible point	Limit curve per soil type; temporary pressure reduction if exceeded
Blasting in rock trench (HCA/MCA	≤ 500 ft (150 m)	1.0 in/s (25 mm/s)	Multiple seismographs; real-time alert system	Enhanced controls in HCA/MCA; tighter limits due to consequence classification
Heavy compaction equipment	≤ 100 ft (30 m)	2.0 in/s (50 mm/s)	Seismograph or visual inspection protocol	May require matting or operational restrictions; coordinate with existing operator
Pile driving / impact operations	≤ 200 ft (60 m)	2.0 in/s (50 mm/s)	Seismograph at existing pipe location	Coordinate with existing operator for timing and approval; may require temporary shutdown
HDD / auger boring near existing line	≤ 50 ft (15 m)	0.5 in/s (12 mm/s)	Real-time displacement or strain monitoring on existing pipe	Pre-drill pressure test required; continuous monitoring during operation; contingency shutdown plan

This comprehensive table provides field-level guidance for managing vibration and blasting risks during parallel construction. The table establishes:

Key features:

- Trigger distances that define when each control is activated—progressively tighter for HCA/MCA and trenchless methods where existing facility proximity is greatest.
- Peak Particle Velocity (PPV) limits in both imperial (in/s) and metric (mm/s) units, reflecting current practice based on:
    - USBM RI 8507 and similar vibration damage criteria
    - API RP 1172 and operator internal standards
    - Site-specific soil and pipe characteristics
- Monitoring methods scaled to activity risk:
    - Standard blasting: single seismograph at existing pipe location
    - HCA/MCA blasting: multiple seismographs with real-time alert for immediate intervention

  - HDD: real-time displacement/strain monitoring on existing pipe to catch small movements before they propagate
- Notes column highlighting special requirements:
  - Temporary pressure reduction or shutdown triggers
  - Enhanced controls in consequence areas
  - Contingency planning for trenchless operations

Application in practice:

- For blasting plans: Use the trigger distance to determine if blasting notification, monitoring, and approval is required. For example, if blasting is planned 250 ft from an existing line in non-HCA terrain, the 300 ft threshold is triggered; if in HCA, the 500 ft threshold applies (more conservative).
- For compaction or heavy equipment: Assess whether the activity is within 100 ft of the existing facility. If yes, establish seismographic or visual monitoring protocol and confirm that vibration limits are not exceeded before proceeding.
- For HDD/auger near existing lines: The tight 50 ft trigger and low 0.5 in/s PPV limit reflect the mechanical complexity of drilling near live pipelines. Real-time strain monitoring allows immediate detection of annular pressure buildup or unexpected soil response that could compromise clearance.

References and basis:

The PPV limits are aligned with:

- API RP 1172, Appendix F: Guidance on vibration limits for underground pipelines
- PRCI research on blast loading effects on buried pipelines
- CSA Z662 Section 4: Construction-phase requirements for parallel pipelines
- AS 2885 Part 1: Australian Standard for gas transmission pipelines, with similar guidance

Documentation requirement:

- All vibration monitoring results should be recorded, reviewed, and filed as part of daily construction logs (Section 6.7.1). Exceedances of PPV limits trigger immediate notification to the existing facility operator and engineering review before work resumes.

6.3.6.3. Monitoring should be conducted by qualified personnel using calibrated seismographs or equivalent instrumentation.

6.3.6.4. If vibration limits are exceeded, work should stop immediately and the existing facility operator notified. Resumption requires joint approval and may necessitate operational adjustments (pressure reduction, additional monitoring).

6.3.7. Physical Barriers and Load Management

6.3.7.1. Where construction equipment or vehicles must cross over or operate near exposed or shallow-buried existing facilities, the design should specify:

a) load-bearing mats or temporary bridges to distribute loads;

b) maximum allowable equipment weights and axle configurations;

c) designated crossing points with signage and supervision.

6.3.7.2. Trench boxes and protective barriers should be installed where excavation could expose workers or equipment to existing facility hazards (e.g., gas release).

6.3.8. Permit-to-Work System

6.3.8.1. A daily or activity-based permit-to-work should be issued for ground disturbance within the AEA.

6.3.8.2. The permit should include:

a) work location, scope, and methods

b) identification of existing facilities and clearances

c) applicable controls from this section (EFR, soft-dig, equipment restrictions, monitoring)

d) sign-off by construction supervision and EFR authorization

6.3.8.3. Permits should be retained as part of project records.

6.4. Sequencing Readiness and Reviews

6.4.1. Joint Readiness Review

6.4.1.1. Before entering the AEA for the first time in any segment, the new pipeline operator and existing facility operator should conduct a Joint Readiness Review (JRR).

6.4.1.2. The JRR should confirm:

a) accurate alignment and marker placement for existing facilities (via SUE Quality Level A at conflict points)

b) all known crossings and conflicts daylighted and surveyed

c) blasting, HDD, or other high-risk plans reviewed and approved

d) EFR assignment and contact information

e) emergency response procedures communicated to field crews

f) permit-to-work and communication protocols established

6.4.1.3. The outcome should be documented in a Readiness Certificate or equivalent, signed by both parties' authorized representatives.

6.4.1.4. A photographic record of field conditions and marker placement is recommended.

6.4.2. Daily or Shift Readiness Checks

6.4.2.1. Each day or shift, prior to commencing AEA activities, a brief readiness check should confirm:

a) EFR on-site and briefed

b) equipment restrictions in place

c) monitoring active (if required)

d) no changes to planned activities without review and approval

6.5. Crossings and Directional Drilling

6.5.1. Crossing Design and Execution

6.5.1.1. All crossings of existing facilities (over or under) should be designed and executed in accordance with applicable standards (e.g., API RP 1102, CSA Z662, AS 2885) and documented in the encroachment agreement.

6.5.1.2. Crossing plans should address:

a) vertical and horizontal clearances (see Section 5.3.2)

b) protective measures (e.g., casing, concrete slabs, marker posts)

c) construction methodology (open-cut, HDD, micro tunneling);

d) stress, thermal, and load analyses where necessary

6.5.2. Horizontal Directional Drilling (HDD) Near Existing Facilities

6.5.2.1. Where HDD is used within 50 ft (15 m) horizontal or 10 ft (3 m) vertical of an existing facility:

a) a detailed drill path profile with clearances should be prepared and approved by the existing operator

b) annular pressure management plan should limit risk of frac-out or loss of circulation affecting the existing facility

c) real-time drill path tracking (e.g., electromagnetic or gyroscopic) should be used

d) contingency plans for intersecting the existing facility (including immediate shutdown, notification, and remediation) should be established

6.5.2.2. Pressure testing of the drilled section should be conducted before pulling the carrier pipe if near an existing facility.

6.6. Damage, Repairs, and Incident Reporting

6.6.1. Incident Notification

6.6.1.1. Any contact with, damage to, or suspected compromise of an existing facility should be immediately reported to the existing facility operator and the EFR.

6.6.1.2. Work in the immediate area should stop; pending joint assessment.

6.6.2. Damage Assessment and Repair

6.6.2.1. The existing facility operator should assess the damage and determine repair requirements, which may include:

a) visual and NDT inspection (e.g., UT, MFL, radiography)

b) coating repair or replacement

c) pipeline repair (sleeve, cut-out, re-routing)

d) CP system reconnection or adjustment

e) pressure testing or ILI verification

6.6.2.2. Restoration of disturbed portions of the existing facility ROW should be to the satisfaction of all parties, including authorizing agencies.

6.6.3. Non-Conformance and Corrective Action

6.6.3.1. Any deviation from the approved CEP, encroachment agreement, or these Guidelines within the AEA should be documented as a Non-Conformance Report (NCR) or Corrective Action Request (CAR).

6.6.3.2. The NCR/CAR should include:

a) description of deviation and root cause

b) immediate corrective action taken

c) engineering review and approval if the deviation affects separation, shielding, or mitigation

d) update to as-built documentation

6.6.3.3. Backfill or cover should not proceed until the deviation is closed and as-builts updated.

6.7. **Construction Documentation**

6.7.1. Daily Construction Logs

6.7.1.1. The new pipeline operator should maintain joint construction logs for all work within the Encroachment Area, including:

a) date, location, and scope of activities

b) EFR presence and any work stoppages or concerns

c) deviations from plan and their resolutions

d) vibration or monitoring data

e) observed conditions of existing facilities (damage, coating holidays, exposure)

6.7.1.2. Logs should be shared with the existing facility operator on request or at agreed intervals.

6.7.2. As-Built Data Capture

6.7.2.1. During construction, the new pipeline operator should collect survey-grade as-built data for:

a) new pipeline centerline (XYZ coordinates)

b) depth of cover at crossings and representative stations

c) all CP/AC mitigation assets installed (test points, bonds, grounds, anodes)

d) coating repairs or modifications to existing facilities

e) ROW features (markers, signs, access gates)

6.7.2.2. As-built data should be provided to the existing facility operator in agreed formats (e.g., GIS shapefile, CAD, database) prior to final project acceptance (see Section 7.3).

6.8. Sample Construction Control Checklist

The following checklist is provided to support field execution compliance:

Pre-Entry to Active Excavation Area (AEA):

- Joint Readiness Review (JRR) completed and signed?
- EFR assigned, contact confirmed, and on-site?
- Existing facility markers verified within last 7 days?
- All conflict points daylighted (SUE Level A)?
- Permit-to-work issued for today's activities?
- Equipment restrictions in place (toothless buckets, etc.)?
- Blasting/vibration plan approved and monitoring active (if applicable)?
- Emergency contacts and stop-work authority understood by crew?

During Work in AEA:

- EFR present and aware of current activities?
- Visual confirmation of existing facility location before mechanical excavation?
- Soft-dig used within Tolerance Zone (≤2 ft)?
- Trench stability and support adequate; no undermining?
- Vibration limits not exceeded (if monitoring)?
- Load management (mats, crossings) in place where required?
- Any deviations or near-misses reported and logged?

End-of-Shift / Activity Close-Out:

- Debrief with EFR on work completed and concerns?
- Construction log updated with activities, issues, and EFR sign-off?
- As-built data captured for new installations or existing facility exposure?
- Work area secured; existing facility protected (backfill, barriers)?
- Permit-to-work closed and filed?

7. Post Construction Integrity and Monitoring

7.1. General

7.1.1. Following completion of construction in the Encroachment Area, the operators should establish and maintain a post-construction integrity program to verify that construction has not compromised long-term safety or performance of co-located facilities.

7.1.2. The program should include:

a) baseline surveys and commissioning (Section 7.2)

b) as-built data management and turnover (Section 7.3)

c) ongoing monitoring and risk-tiered surveillance (Section 7.4)

d) post-construction review and lessons learned (Section 7.5)

7.2. Post-Construction Baseline Surveys and Commissioning

7.2.1. Survey Requirements

7.2.1.1. A suite of baseline surveys should be conducted on both the new and existing facilities following construction to establish a reference for future integrity management.

7.2.1.2. The scope and timing of surveys are defined in Table 7-1 and should be tailored to corridor risk (HCA/MCA status, interaction concerns).

Table 7-1 Post-Construction Baseline Survey Requirements

Survey Type	Purpose	Timing	Acceptance Criteria	Notes
Close Interval Survey (CIS) / Direct Current Voltage Gradient (DCVG)	Establish CP baseline and detect coating defects introduced during construction	Within 3 months post-construction; before final acceptance	CP potentials ≥-850 mV CSE (steel); no new coating defects >5 mm² on new or existing pipe	Mandatory for all parallel segments; identifies holiday locations for repair prioritization
AC Voltage and Current Survey	Verify AC interference mitigation effectiveness; confirm touch/step voltages and AC current density within limits	Within 6 months post-construction if AC mitigation installed; before energizing new AC facility	Touch voltage ≤15 Vrms; step voltage ≤10 Vrms; AC current density ≤100 mA/cm² (per coating condition)	Required where AC modeling triggered mitigation; testing conducted at representative coating defects
Inline Inspection (ILI) – Magnetic Flux Leakage (MFL) or Ultrasonic (UT)	Detect anomalies (dents, gouges, stress concentrations) from construction; baseline for future integrity assessment	1–3 years post-construction for existing and new lines; prioritize HCA/MCA corridors	No reportable anomalies per ASME B31.8 or operator IMP; dents <10% wall thickness; no new metal loss	Coordinate timing with both operators; high-cost survey; justifiable for HCA and high-interaction corridors
Right-of-Way (ROW) and Aerial	Verify restoration quality, slope	Immediate post-construction	No settlement >2 inches over 300 ft;	Ground and/or aerial (drone,

Inspection	stability, no encroachments, no settlement or erosion; detect unauthorized third-party activity	(mobilization); repeat at 6–12 months to assess settlement	slope stable (no slides); no erosion channels; no visible encroachments or markers missing	LiDAR); low-cost baseline; critical for risk trending over project lifecycle
Coating Condition Assessment (Visual / NDT)	Document baseline coating condition on both existing and new facilities; identify areas for repair or monitoring	Concurrent with CIS or within 3 months post-construction	≥95% of new pipe coating in good condition (per API 579); existing pipe holidays <5% of external surface area	Defects >5 mm² or holidays requiring corrosion control prioritized for monitoring or repair
Stress and Strain Analysis (from thermal or vibration loading)	Verify no permanent deformation or residual stress from construction on existing pipe; confirm elastic recovery	Post-construction if vibration/blasting/HDD exposure significant; within 6 months	Measured strain <30% of allowable elastic strain; no plastic deformation; relief valves not triggered	For HDD crossings, strain gauges installed during construction may remain for trending; contact pressure monitoring if pipe supported

Post-Construction Survey Prioritization and Sequencing

- **Tier 1 (Mandatory):** CIS, ROW initial, Coating assessment → Complete within 3 months
- **Tier 2 (Conditional):** AC survey, Stress/strain, ROW 6–12 month re-inspection → Complete within 6 months
- **Tier 3 (Recommended):** ILI → 1–3 years post-construction

Corrective Actions If Results Unacceptable – Non-conformance documentation, root cause analysis, corrective action examples, acceptance sign-off

Integration with Ongoing Integrity Management (Section 7.4) – How baseline results feed into JIMP

7.2.2. Close Interval Survey (CIS) and CP Commissioning

7.2.2.1. CIS should be conducted on all parallel segments to establish CP baseline and detect coating defects introduced during construction.

7.2.2.2. CP commissioning should confirm:

a) all test points functional and accessible

b) CP potentials meet design criteria (e.g., ≤-850 mV CSE for steel pipelines)

c) no interference or shielding between parallel CP systems

d) mitigation assets (bonds, decouplers, grounds) installed per design

7.2.3. AC Voltage and Current Surveys

7.2.3.1. Where AC interference modeling triggered mitigation, post-construction surveys should verify:

a) touch and step voltages ≤ acceptance criteria (e.g., ≤15 Vrms)

b) AC current density at representative coating defects within corrosion control limits

c) mitigation systems (gradient control mats, bonds) properly grounded and effective

7.2.4. Inline Inspection (ILI) Timing

7.2.4.1. Where feasible, an ILI run should be conducted on both existing and new pipelines within 1–3 years post-construction to detect any construction-related anomalies not evident during visual or external inspection.

7.2.4.2. ILI timing and technology selection should be coordinated between operators to optimize scheduling and reduce costs.

7.2.5. ROW and Aerial Inspection

7.2.5.1. A comprehensive ROW inspection (ground and/or aerial, including drone or LiDAR where appropriate) should be conducted immediately post-construction and again at 6–12 months to:

a) verify restoration quality and slope stability

b) detect settlement, erosion, or exposure

c) confirm no unauthorized encroachments or third-party activity

7.2.6. Acceptance Criteria and Corrective Action

7.2.6.1. Survey results should be evaluated against the acceptance criteria in Table 7-1 and applicable operator standards.

7.2.6.2. Where deficiencies are identified (e.g., CP potentials out of range, coating indications requiring action, construction damage), corrective action plans should be developed jointly and executed prior to final project acceptance.

7.3. As-Built Documentation and Turnover

7.3.1. As-Built Data Requirements

7.3.1.1. Prior to final project acceptance, the new pipeline operator should provide the existing facility operator(s) with comprehensive as-built documentation including:

a) Centerline and alignment data (XYZ coordinates, stationing) with survey-grade accuracy (±0.1 m horizontal, ±0.05 m vertical).

b) Depth of cover at crossings, valve sites, and representative intervals.

c) CP and AC mitigation assets: test point IDs, coordinates, wiring diagrams, bond locations, grounding details, anode beds.

d) Coating repairs or modifications to existing facilities (location, type, coating system).

e) ROW features: markers, signs, access roads, fencing, above-ground facilities.

f) Deviation records: any approved field changes affecting proximity, shielding, or mitigation.

7.3.1.2. Data should be provided in agreed digital formats (e.g., GIS shapefile, CAD DWG/DXF, database tables, PDF engineering drawings) compatible with each operator's asset management systems.

7.3.2. Data Standards and Interoperability

7.3.2.1. As-built data should conform to industry spatial data standards where available (e.g., ASCE 38, PODS, OGC standards) to facilitate interoperability and future corridor management.

7.3.2.2. Each feature or asset should be assigned a unique identifier with ownership / responsible-party fields and change control metadata.

7.3.3. Turnover Meeting

7.3.3.1. A formal turnover meeting should be held between the new and existing operators to:

a) review as-built documentation for completeness and accuracy

b) transfer baseline survey results and commissioning records

c) confirm ongoing monitoring responsibilities and contact information

d) update encroachment agreements or MOUs to reflect as-built conditions

e) close out outstanding NCRs/CARs

7.3.3.2. The turnover meeting should be documented with a signed acceptance or turnover certificate.

7.4. **Ongoing Monitoring and Surveillance**

7.4.1. Joint Integrity Management Plan (JIMP)

7.4.1.1. Operators sharing a corridor are strongly encouraged to develop a Joint Integrity Management Plan (JIMP) or equivalent framework for ongoing coordination.

7.4.1.2. The JIMP should address:

a) monitoring cadences for CP, AC, and ILI (see Table 7-2 below)

b) joint or coordinated ROW patrols and inspections

c) periodic review of geohazard conditions and seasonal factors

d) communication protocols for integrity findings, incidents, or third-party activity

e) data sharing arrangements and joint integrity databases

f) re-evaluation triggers (see 7.4.3)

7.4.1.3. The JIMP should align with each operator's regulatory Integrity Management obligations (e.g., 49 CFR §§192.935, 195.452; CSA Z662 Annex O).

7.4.2. Risk-Tiered Monitoring Cadence

7.4.2.1. Monitoring intervals should be commensurate with corridor risk, as shown in Table 7-2.

Table 7-2 Ongoing Monitoring Cadence (Risk-Tiered)

Monitoring Activity	Non-HCA/Non-MCA	HCA/MCA	Notes / Triggers for Increased Frequency
Close Interval Survey (CIS) / DCVG for CP trending	Every 3–5 years; annual if marginal potentials (<-850 mV CSE)	Every 1–2 years; annual if HCA with dense population or environmental sensitivity	Detect coating degradation or CP system drift; identify growth of holidays; trigger repair if trend is adverse
Inline Inspection (ILI) – Metal loss and anomaly trending	Every 5–10 years (per operator IMP); more frequent if construction-related anomalies detected	Every 3–5 years; every 1–2 years if high-interaction zone (parallel with close clearance) or significant construction damage	Detect anomaly growth (corrosion, dent propagation); baseline trending; use same technology to ensure comparison; coordinate between operators
AC Voltage and Current Survey (if AC mitigation installed	Every 3–5 years; annually if touch voltage trending upward	Every 1–2 years; annually if near tolerance (touch voltage >10 Vrms)	Confirm mitigation system effectiveness; detect changes in AC field (new power lines, capacity increases); triggers upgrades if limits exceeded
Right-of-Way (ROW) Patrol and Inspection	Annual visual patrol (ground or aerial); detailed inspection every 2–3 years	Semi-annual patrol (minimum); annual detailed inspection; quarterly if geohazard-prone (landslide, flood scour, coastal erosion)	Detect settlement, erosion, marker damage, encroachments, or third-party activity; low-cost trending; critical for risk assessment
CP System Performance Analysis and Anode Trending	Annual review of CIS data; anode performance assessment every 2–3 years	Annual review; detailed assessment every 1–2 years if anode consumption higher than designed	Detect anode depletion or performance decline; forecast replacement timing; ensure continuous protection; document CP drift
Joint Operator Coordination Meetings and Data Review	Annual coordination meeting; data sharing and review per JIMP agreement	Semi-annual or quarterly if active geohazard concerns; after significant third-party activity or incidents in corridor	Share survey results, incident reports, and lessons learned; align monitoring schedules; re-evaluate if corridor changes (new facilities, increased traffic)

7.4.2.2. Monitoring data (CP readings, AC surveys, ILI results, patrol observations) should be trended and evaluated jointly at agreed intervals (e.g., annually) to identify adverse trends or interaction effects.

7.4.3. Re-evaluation Triggers

7.4.3.1. The following events or conditions should trigger re-evaluation of corridor integrity and potential revision of the monitoring program:

a) CP drift beyond design bands (e.g., >50 mV in HCAs, >100 mV elsewhere)

b) ILI anomaly growth or new indications near the parallel facility interface

c) HVAC load increases >20% or addition of new parallel power lines

d) New encroachment or co-located construction (third-party pipelines, utilities, infrastructure)

e) Geohazard activation (slope movement, seismic event, flood/scour)

f) Damage incident or near-miss in the shared corridor

7.4.3.2. Re-evaluation should include updated risk assessment, modeling (if warranted), and adjustment of monitoring or mitigation as necessary.

7.5. Post-Construction Review and Lessons Learned

7.5.1. Post-Construction Review Meeting

7.5.1.1. Within 6 months of final construction acceptance, the new pipeline and existing facility operators should hold a Post-Construction Review Meeting to:

a) identify what worked well and what did not

b) assess the effectiveness of these Guidelines and project-specific measures

c) document near-misses, incidents, and deviations

d) identify corrective actions or process improvements for future projects

7.5.1.2. The meeting should be documented in a structured format (see recommended agenda in Attachment A).

7.5.1.3. Lessons Learned Documentation and Sharing

a) Lessons learned should be documented and retained by each operator for internal continuous improvement.

b) Operators are strongly encouraged to share anonymized lessons learned with INGAA Foundation or other industry bodies to support ongoing evolution of parallel construction practices and periodic Guideline updates.

7.6. Sample Post-Construction Integrity Checklist

Baseline Surveys and Commissioning:

- CIS/DCVG completed on existing and new pipelines?
- CP commissioning confirms potentials within design range?
- AC voltage surveys completed where mitigation installed; acceptance criteria met?
- ILI scheduled or completed; no construction damage anomalies?
- ROW inspection confirms stable restoration and no encroachments?

As-Built Documentation and Turnover:

- As-built centerline and depth data collected and delivered in agreed formats?
- CP/AC mitigation assets documented (test points, bonds, grounds, anodes)?
- Coating repairs and deviations documented and closed?
- Turnover meeting held and acceptance/turnover certificate signed?
- Digital data loaded into each operator's asset management system?

Ongoing Monitoring:

- JIMP or equivalent monitoring plan established and documented?
- Monitoring cadence defined and scheduled (CP, AC, ILI, patrols)?
- Data sharing and communication protocols in place?
- Re-evaluation triggers defined and understood?

Post-Construction Review:

- Review meeting held within 6 months?
- Lessons learned documented and shared with INGAA or industry?
- Recommendations for guideline or process improvements identified?

8. Governance, Documentation, and Change Management

8.1. General

8.1.1. Effective governance of parallel pipeline projects requires clear roles, responsibilities, decision authorities, and change control processes from early planning through operations.

8.1.2. This section establishes minimum governance expectations to ensure traceability of decisions, accountability for deviations, and continuity of information across project phases.

8.2. Interface Management Plan (IMP)

8.2.1. Requirement and Scope

8.2.1.1. For each significant parallel construction project, the new pipeline operator, in coordination with existing facility operator(s), should establish a formal Interface Management Plan (IMP).

8.2.1.2. The IMP should address:

a) project organization and interfaces

b) roles and responsibilities (RACI matrix, see Section 8.3)

c) communication protocols and designated contacts

d) decision-making authorities for deviations, changes, and emergencies

e) documentation standards and records retention

f) dispute resolution procedures

g) change management and deviation control processes (see Section 8.4)

8.2.1.3. The IMP should be a living document, updated as needed throughout the project lifecycle, with revisions distributed to all parties.

8.2.2. Integration with Encroachment Agreements

8.2.2.1. The IMP should be referenced or appended to encroachment agreements to ensure contractual alignment.

8.2.2.2. Where multiple existing operators or corridor users are involved, the IMP should coordinate all interfaces through a single framework.

8.3. Roles and Responsibilities (RACI Matrix)

8.3.1. RACI Framework

8.3.1.1. Roles and responsibilities for key activities should be defined using a RACI matrix or equivalent:

- **R** = Responsible (does the work)
- **A** = Accountable (final authority/approval; only one "A" per activity)
- **C** = Consulted (input required before decision or action)
- **I** = Informed (kept up to date on progress or results)

8.3.2. Sample RACI Matrix

8.3.2.1. Table 8-1 provides a sample RACI matrix for typical parallel construction activities. This should be tailored to project-specific organizations and agreements.

Table 8-1 Sample RACI Matrix

Activity	New Pipeline Operator	Existing Operator	Co-location Engineer	Contractor
Project Initiation & Encroachment Agreement Negotiation	A, R Leads negotiation; proposes terms; has final approval of agreement scope and liability allocation	A, R Reviews and negotiates terms; must approve all design assumptions, mitigation requirements, and cost allocation	C Provides input on technical feasibility; flags any known issues or constraints	I Informed of final agreement terms; may provide constructability input if engaged early
Regulatory Permitting & Authority Coordination	A, R Prepares permit applications; manages agency correspondence; obtains all required permits	C, I Consulted on parallel facility impacts; may need to support with letters or certifications	C Provides technical documentation on mitigation measures; may be required to attend agency meetings	I Informed of permitting schedule and any constraints affecting construction timeline
Design Review & Interaction Analysis	R Prepares baseline design; manages design consultant; ensures design meets own standards	C, A Consulted on design details affecting existing facility; accountable for sign-off on crossing plans, mitigation measures	A, R Leads interaction analysis; integrates designs; approves clearances and mitigation; has final authority on engineering adequacy	I Informed of final design; may provide constructability feedback if design is preliminary
Risk Assessment & Mitigation Design	R Collects baseline design data; provides soil, geohazard, and facility information	C, A Provides existing facility details (material, diameter, design pressure, age, condition); must approve mitigation measures	A, R Leads risk assessment; selects appropriate models/tools; designs mitigation; has final authority on adequacy	C Provides constructability input; may identify site constraints affecting mitigation feasibility
Construction Execution Plan (CEP) Development	A, R Leads CEP development; coordinates with contractor and existing operator; must approve final plan	C, A Consulted on construction methods affecting existing facility; must approve EFR assignment, soft-dig procedures, blasting plans	C Reviews CEP for adequacy of controls; may request additional measures if risk warrants	R Proposes construction methods and sequencing; details how Table 6-1 controls will be implemented

Field Construction Supervision	I	C, R (ERF Assignment)	C (as needed)	A, R
	Informed via daily logs; may conduct weekly reviews but not day-to-day field presence	Assigns and pays for EFR; EFR is on-site during AEA work; has authority to stop work	May visit site during high-risk activities (HDD, blasting, crossings); available for consultation	Accountable for field execution per CEP; Construction Supervisor on-site daily
Deviation Approval & Engineering Change Control	C, R	A	A, R	R (requests)
	Consulted on deviations affecting new pipeline; approves if within design flexibility	Has final approval authority on any deviation affecting separation, mitigation, or existing facility protection	Conducts engineering evaluation; recommends approval or rejection; provides technical justification	Submits deviation request; implements approved deviations; documents in as-builts
Incident Investigation & Root Cause Analysis	C, R	A, R	C	R (provides data)
	Participates in investigation; shares construction records; implements corrective actions	Leads investigation (facility was impacted); determines cause and remediation	Provides expert input on design adequacy; assesses whether design changes warranted	Provides detailed facts of what happened; crew interviews; equipment/method analysis
As-Built Documentation & Data Delivery	R	C, I	C	R (collects data)
	Compiles and delivers all as-built data to Existing Operator in agreed formats	Consulted during data compilation; receives final delivery; loads into asset management system	Reviews as-built data for completeness and accuracy vs. design intent	Collects field survey data (centerline, depths, CP assets, coating repairs); delivers to New Operator
Post-Construction Baseline Surveys	A	A	C	R (coordinates)
	Accountable for conducting surveys on its pipeline and coordinating timing with Existing Operator	Accountable for conducting surveys on its pipeline; participates in joint planning	Consulted on survey protocols, acceptance criteria, interpretation of results	Coordinates survey mobilization, scheduling, logistics; may conduct under contract to operator
Ongoing Monitoring & JIMP Execution	A	A	I	I
	Accountable for executing its portion of JIMP (CIS, ILI, ROW patrols on new pipeline)	Accountable for executing its portion of JIMP (CIS, ILI, ROW patrols on existing pipeline)	Informed of JIMP execution; available if re-evaluation triggered	Informed of ongoing monitoring; typically no role post-construction

Change Management & Re-Evaluation Trigger Response	A, R Accountable for evaluating changes to its facilities or operations; proposes mitigation if needed	A, R Accountable for evaluating changes to its facilities or operations; may initiate re-evaluation if corridor risk increases	C Consulted if re-evaluation requires technical assessment (updated modeling, risk analysis)	I Informed if change requires construction or modifications

8.3.3. Co-location Engineer of Record

8.3.3.1. For projects with significant interaction risk (e.g., small separations, HCA/MCA corridors, multiple interaction domains), a Co-location Engineer of Record should be designated.

8.3.3.2. This individual should:

a) integrate all interaction analyses (mechanical, thermal, AC/CP, geohazard)

b) prepare or review engineering deviation cases

c) coordinate technical reviews and approvals across operators

d) ensure consistency and traceability of design decisions

e) be available for consultation during construction and post-construction phases

8.3.3.3. The Co-location Engineer should be a licensed professional engineer (P.E., P.Eng., or equivalent) with relevant expertise.

8.4. Deviation Control and Change Management

8.4.1. Scope of Deviations

8.4.1.1. A deviation is any variance from the approved design, encroachment agreement, or these Guidelines that may affect:

a) separation distances or proximity controls

b) shielding, barriers, or protective structures

c) CP/AC mitigation measures or monitoring points

d) construction methods or sequencing within the CE

e) as-built conditions of existing or new facilities

8.4.2. Deviation Approval Process

8.4.2.1. Any proposed deviation within the CE should be documented and approved before implementation.

8.4.2.2. The deviation documentation should include:

a) description of deviation and reason (e.g., unforeseen ground conditions, design improvement)

b) technical evaluation of impact on safety, integrity, and interaction risk

c) proposed mitigation or compensating controls

d) approval signatures from authorized representatives of both operators (and Co-location Engineer where assigned)

8.4.2.3. Where the deviation affects critical parameters (e.g., encroachment into HCA with reduced separation, change to CP mitigation design), peer or independent technical review may be required.

8.4.3. Field Change Authority

8.4.3.1. The EFR and construction supervision should have authority to stop work and require engineering review for field conditions or proposed change that may compromise safety or integrity of the existing facility.

8.4.3.2. Minor field adjustments (e.g., local alignment shifts of <3 ft that maintain or increase separation and do not affect other constraints) may be authorized by the EFR and field supervision, provided they are documented and confirmed in as-builts.

8.4.3.3. All other deviations require formal review per 8.4.2.

8.4.4. Deviation Register

8.4.4.1. A Deviation Register should be maintained throughout construction, tracking:

a) deviation ID and date

b) location and description

c) technical review and approval status

d) implementation status

e) as-built documentation status

8.4.4.2. The Deviation Register should be reviewed at project milestones and closed prior to final acceptance.

8.4.5. As-Built Update Requirement

8.4.5.1. No backfill or cover should proceed over a deviation location until:

a) the deviation has been technically reviewed and approved;

b) as-built survey data has been captured; and

c) the Deviation Register is updated.

8.5. Documentation Standards and Records Retention

8.5.1. Minimum Document Set

8.5.1.1. The following documents should be generated, maintained, and retained for the life of the facilities plus a period consistent with regulatory and company requirements:

a) Encroachment agreements and MOUs

b) Interface Management Plan (IMP)

c) Risk assessments and interaction analyses (mechanical, thermal, AC/CP, geohazard)

d) Engineering deviation cases and approvals

e) Construction Execution Plan (CEP) and blasting/vibration plans

f) Daily construction logs and permit-to-work records for CE activities

g) Deviation Register and NCR/CAR records

h) As-built drawings, survey data, and CP/AC mitigation details

i) Baseline survey results and commissioning records

j) Post-construction review and lessons learned documentation

8.5.2. Digital Integration and Accessibility

8.5.2.1. Records should be maintained in accessible digital formats (e.g., GIS-integrated, searchable PDFs, database repositories).

8.5.2.2. Where mature, digital twin or integrated corridor management platforms are encouraged to support ongoing risk management and future co-location projects.

8.5.2.3. Records should be available for regulatory inspection and for use in future integrity assessments, expansions, or third-party projects in the corridor.

8.6. Memoranda of Understanding (MOUs) and Long-Term Coordination

8.6.1. MOUs for Ongoing Operations

8.6.1.1. Where operators share a corridor with significant interaction or operational interdependencies, a Memorandum of Understanding (MOU) or similar agreement should be established for long-term coordination.

8.6.1.2. The MOU should address:

a) ownership and maintenance of shared CP/AC mitigation assets

b) access to test points, monitoring equipment, and shared facilities

c) joint emergency response protocols and mutual aid

d) data sharing for integrity management

e) notification requirements for future maintenance, expansions, or third-party activities in the corridor

f) dispute resolution and escalation procedures

8.6.1.3. MOUs should be reviewed and updated periodically (e.g., every 5 years or upon significant corridor changes).

8.6.2. Coordination with Future Corridor Users

8.6.2.1. When additional pipelines or utilities are proposed in an already-parallel corridor, existing operators should:

a) provide as-built data and lessons learned to the new entrant

b) update MOUs and IMPs to include the new party

c) reassess cumulative interaction risks (CP interference, thermal coupling, emergency response complexity)

8.7. Sample Governance and Documentation Checklist

Interface Management:

- IMP developed and approved by all parties?
- RACI matrix defined and communicated to project team?
- Co-location Engineer of Record assigned (if required)?
- Designated Contacts established and contact information current?

Deviation and Change Control:

- Deviation approval process documented and understood by field teams?
- Deviation Register established and maintained?
- All deviations technically reviewed and approved before backfill?
- As-builts updated to reflect all approved deviations?

Documentation and Records:

- Minimum document set identified and responsibility assigned?
- Digital formats agreed and data loaded into asset management systems?
- Records retention plan consistent with regulatory and company requirements?
- MOUs for long-term operations executed and filed?

Regulatory and Third-Party Coordination:

- Records available for regulatory inspection on request?
- Future corridor users notified and provided access to relevant data?
- Encroachment agreements and MOUs updated to reflect current corridor status?

REFERENCES

Standards, Codes, Regulations, and Technical Documents

This section provides a comprehensive list of regulations, codes, standards, technical specifications, and reference documents cited throughout these Guidelines or relevant to the planning, design, construction, and operation of parallel pipeline projects.

R.1 U.S. Federal Regulations

R.1.1 Pipeline and Hazardous Materials Safety Administration (PHMSA)

49 CFR Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

- §192.3 – Definitions
- §192.5 – Class locations
- §192.112 – Additional design requirements for steel pipe using alternative maximum allowable operating pressure
- §192.150 – Passage of internal inspection devices
- §192.327 – Cover
- §192.328 – Additional construction requirements for steel pipe using alternative maximum allowable operating pressure
- §192.465 – External corrosion control: Monitoring
- §192.467 – External corrosion control: Electrical isolation
- §192.473 – External corrosion control: Interference currents
- §192.490 – Corrosion control records
- §192.614 – Damage prevention program
- §192.631 – Public awareness
- §192.903 – What definitions apply to this subpart? (Integrity Management)
- §192.905 – How does an operator identify a high consequence area?
- §192.907 – What are the required elements of an integrity management plan?
- §192.909 – What are the baseline assessment requirements?
- §192.911 – What are the continuing integrity assessment requirements?
- §192.913 – What must an operator do to continually identify high consequence areas?
- §192.917 – How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
- §192.921 – How is the baseline assessment to be conducted?
- §192.923 – When must an operator complete a baseline assessment?
- §192.933 – What actions must an operator take to address integrity issues?

49 CFR Part 195 – Transportation of Hazardous Liquids by Pipeline

- §195.2 – Definitions
- §195.106 – Internal design pressure
- §195.228 – Isolation valves
- §195.248 – Cover over buried pipelines
- §195.402 – Procedural manual for operations, maintenance, and emergencies
- §195.442 – Damage prevention program
- §195.452 – Pipeline integrity management in high consequence areas
- §195.573 – What must I do to monitor external corrosion control?
- §195.583 – What must I do to monitor atmospheric corrosion control?
- §195.585 – What must I do to correct corroded pipe?

R.1.2 Federal Energy Regulatory Commission (FERC)

18 CFR Part 157 – Applications for Certificates of Public Convenience and Necessity and for Orders Permitting and Approving Abandonment Under Section 7 of the Natural Gas Act

- §157.21 – Pre-filing procedures and review process for LNG terminal facilities; capitalized terms
- §157.22 – Notices required under the optional pre-filing process

18 CFR Part 380 – Regulations Implementing the National Environmental Policy Act

- §380.12 – Environmental reports for Natural Gas Act applications
- §380.15 – Siting and maintenance requirements

R.2 Canadian Regulations and Standards

R.2.1 Canadian Standards Association (CSA)

CSA Z662-2019/2023 – Oil and Gas Pipeline Systems

- Clause 3 – General design
- Clause 4 – Design requirements
- Clause 5 – Material
- Clause 6 – Construction and joining
- Clause 7 – Inspection and testing
- Clause 8 – Operations and maintenance
- Clause 9 – Corrosion control
- Clause 10 – Integrity management programs
- Annex C – Strain-based design for pipelines
- Annex O – Assessment and management of geohazards for pipelines

R.2.2 Provincial and Territorial Regulations

Alberta

- Alberta Energy Regulator – Pipeline Rules (Alberta Regulation 91/2005)
- Alberta One-Call Corporation – Requirements for Notification

British Columbia

- British Columbia Oil and Gas Commission – Pipeline Regulation (BC Reg. 281/2010)
- British Columbia One-Call Centre – Safe Excavation Requirements

Ontario

- Technical Standards and Safety Authority (TSSA) – Fuel Safety Program

R.3 International Standards and Codes

R.3.1 Australian Standards (AS)

AS 2885 – Pipelines – Gas and Liquid Petroleum

- AS 2885.1-2018 – Design and construction
- AS 2885.3-2018 – Operation and maintenance
- AS 2885.6-2018 – Pipeline safety management

R.3.2 United Kingdom Standards

IGEM/TD/1 Edition 6 (2020) – Steel Pipelines and Associated Installations for High Pressure Gas Transmission

- Section 7 – Design considerations for pipelines in close proximity to other services
- Section 11 – Construction
- Section 13 – Commissioning and testing
- Section 15 – Operation, maintenance, and inspection

R.3.3 International Organization for Standardization (ISO)

ISO 13623:2017 – Petroleum and Natural Gas Industries – Pipeline Transportation Systems

- Section 6 – Design principles
- Section 9 – Construction
- Section 10 – Corrosion control
- Annex A – Risk assessment methodologies

R.4 American Petroleum Institute (API) Standards and Recommended Practices

R.4.1 Design and Construction

API Recommended Practice 1172 (2019) – Recommended Practice for Construction Parallel to Existing Underground Transmission Pipelines

- Section 2 – Planning and design
- Section 3 – Pre-construction coordination
- Section 4 – Construction practices
- Section 5 – Post-construction activities
- Appendix A – Risk assessment methodology
- Appendix B – Construction control measures

API Recommended Practice 1102 (2016) – Steel Pipelines Crossing Railroads and Highways

API Standard 1104 (2021) – Welding of Pipelines and Related Facilities

API Recommended Practice 1109 (2015) – Marking of Subsurface Facilities

API Recommended Practice 1110 (2013) – Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide

R.4.2 Operations and Integrity Management

API Recommended Practice 1160 (2019) – Managing System Integrity for Hazardous Liquid Pipelines

API Recommended Practice 1173 (2022) – Pipeline Safety Management Systems

API Standard 579-1/ASME FFS-1 (2021) – Fitness-For-Service

R.4.3 Vibration and Dynamic Loading

API Recommended Practice 1130 (2019) – Calculating the Secondary Response of Onshore and Offshore Production Piping

R.5 NACE International/AMPP (Association for Materials Protection and Performance)

NACE SP0169/AMPP SP21424 (2022) – Control of External Corrosion on Underground or Submerged Metallic Piping Systems

NACE TM0497-2015/AMPP TM21424 – Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems

NACE SP0177/AMPP SP21416 (2022) – Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

NACE TM0101-2012 – Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems

NACE SP0388/AMPP SP21112 (2020) – Inspection of Pipelines and Laterals

R.6 American Society of Civil Engineers (ASCE)

ASCE 38-22 – Standard Guideline for the Collection and Depiction of Existing Subsurface Utility Data

- Section 4 – SUE Quality Levels
- Section 5 – Horizontal and vertical accuracy requirements

- Section 6 – Documentation standards

ASCE/SEI 7-22 – Minimum Design Loads and Associated Criteria for Buildings and Other Structures

- Chapter 22 – Seismic ground motion and response
- Appendix C – Seismic design parameters

ASCE Geotechnical Baseline Report Guidelines

ASCE Manual of Practice No. 127 – Seismic Design of Liquid-Containing Concrete Structures and Commentary (2016)

R.7 Common Ground Alliance (CGA)

CGA Best Practices – Version 20.0 (2023) or latest

- Practice 1-0 – Enhance Public Awareness of Damage Prevention through Broad Outreach and Targeted Education
- Practice 2-0 – Establish and Utilize a One-Call Notification System
- Practice 2-4 – Plan and Design Projects to Avoid Damage
- Practice 3-0 – Respond to Notifications by Locating and Marking Facilities
- Practice 4-0 – Ensure Proper Excavation Practices and Facility Protection through Education, Training and Compliance
- Practice 4-9 – Obtain positive response
- Practice 5-0 – Establish and Sustain Effective Stakeholder Engagement
- Practice 5-18 – Provide for competent facility representatives
- Practice 5-19 – Maintain reasonable excavation tolerance zone
- Practice 9-0 – Design and Operate One-Call Centers Effectively

R.8 INGAA Foundation and DNV GL Technical Documents

INGAA Foundation Report (2019) – AC Interference on Corrosion Coated Pipelines: Mitigation and Monitoring Guidelines

DNV GL Recommended Practice DNVGL-RP-F103 (2017) – Cathodic Protection of Submarine Pipelines by Galvanic Anodes

DNV GL Recommended Practice DNVGL-RP-F106 (2021) – Factory Applied External Pipeline Coatings for Corrosion Control

INGAA/DNV GL AC Interference Severity Matrix (2019) – Referenced for AC interference screening and mitigation prioritization

R.9 Pipeline Research Council International (PRCI)

PRCI Report PR-015-163705-R01 (2019) – Assessment and Management of Cracking in Pipelines

PRCI Report PR-328-133703-R01 (2018) – Geohazard Risk Management for Oil and Gas Pipelines

PRCI Report PR-015-153708-R01 (2019) – Guidelines for Constructing Natural Gas Pipelines through Areas Prone to Landsliding and Subsidence

PRCI Report PR-015-134003-R01 (2018) – State-of-the-Art: AC and DC Interference on Pipelines – Measurements, Analysis, Mitigation

PRCI Catalog No. L52292e (2009) – Guidelines for the Design and Construction of Crossings of Natural Gas Pipelines and High Voltage Electric Transmission Lines

R.10 American Society of Mechanical Engineers (ASME)

ASME B31.4 (2022) – Pipeline Transportation Systems for Liquids and Slurries

ASME B31.8 (2022) – Gas Transmission and Distribution Piping Systems

- Chapter I – General Requirements
- Chapter II – Steel Line Pipe
- Chapter III – Pipe Components and Fabrication
- Chapter IV – Design and Construction of Gas Transmission and Distribution Piping Systems
- Chapter V – Welding
- Chapter VII – Corrosion Control
- Chapter VIII – Operation and Maintenance

ASME B31.8S (2020) – Managing System Integrity of Gas Pipelines

- Section 2 – Pipeline integrity management program elements
- Section 5 – Threat assessment and risk evaluation
- Section 6 – Data integration and analysis
- Section 7 – Continual evaluation and assessment

R.11 American Welding Society (AWS)

AWS D1.1 (2020) – Structural Welding Code – Steel

AWS D10.9M/D10.9 (2020) – Welding of Metals – General Practices

R.12 Environmental and Land Use Regulations

R.12.1 United States

National Environmental Policy Act (NEPA) – 42 U.S.C. §4321 et seq.

Clean Water Act (CWA) – Section 404 Wetlands Permits (33 U.S.C. §1344)

Endangered Species Act (ESA) – 16 U.S.C. §1531 et seq.

Rivers and Harbors Act – Section 10 Permits (33 U.S.C. §403)

Executive Order 11990 – Protection of Wetlands

Bureau of Land Management (BLM) Right-of-Way Regulations – 43 CFR Part 2800

U.S. Forest Service Special Use Regulations – 36 CFR Part 251

R.12.2 Canada

Canadian Environmental Assessment Act, 2012 (S.C. 2012, c. 19, s. 52)

Species at Risk Act (S.C. 2002, c. 29)

Fisheries Act (R.S.C., 1985, c. F-14)

R.13 Geotechnical and Geohazard Assessment Standards

ASTM D1586 (2018) – Standard Test Method for Standard Penetration Test (SPT) and Split-Barrel Sampling of Soils

ASTM D2487 (2017) – Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)

ASTM D4428/D4428M (2014) – Standard Test Methods for Crosshole Seismic Testing

ASTM D7400 (2019) – Standard Test Methods for Downhole Seismic Testing

USGS Seismic Hazard Mapping Program (2018) – National Seismic Hazard Model

Earthquake Engineering Research Institute (EERI) Publications – Liquefaction and Ground Failure Reconnaissance

CSA Z662 Annex O (2019/2023) – Assessment and Management of Geohazards for Pipelines

Geotechnical Engineering Circular No. 5 (FHWA-NHI-16-072, 2016) – Geotechnical Site Characterization Reference Manual

R.14 AC Interference and Electrical Safety Standards

IEEE Std 80-2000 (R2015) – IEEE Guide for Safety in AC Substation Grounding

IEEE Std 81-2012 – IEEE Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Grounding System

IEEE Std 367-2012 – IEEE Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault

NACE SP0177/AMPP SP21416 (2022) – Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems (also listed in R.5)

CIGRE Technical Brochure 095 (1995) – Guide on the Influence of High Voltage AC Power Systems on Metallic Pipelines

IEC 61936-1 (2021) – Power Installations Exceeding 1 kV AC

R.15 Vibration and Blasting Standards

ISEE (International Society of Explosives Engineers) Blasters' Handbook (18th Edition, 2011)

U.S. Bureau of Mines RI 8507 (1980) – Structure Response and Damage Produced by Ground Vibration from Surface Mine Blasting

DIN 4150-3 (1999) – Structural Vibration – Effects of Vibration on Structures (German Standard for Vibration Limits)

British Standard BS 5228-2:2009+A1:2014 – Code of Practice for Noise and Vibration Control on Construction and Open Sites – Part 2: Vibration

API RP 1130 (2019) – Calculating the Secondary Response of Onshore and Offshore Production Piping (also listed in R.4.3)

R.16 In-Line Inspection (ILI) and Integrity Assessment Standards

NACE SP0102/AMPP SP21424 (2017) – Inline Nondestructive Inspection of Pipelines

API Specification 1163 (2013) – Seamless and Welded Steel Line Pipe for Pipeline Transportation Systems

API Standard 650 (2020) – Welded Tanks for Oil Storage (applicable to hydrostatic test procedures)

ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (2021) – Rules for Construction of Pressure Vessels

PHMSA Advisory Bulletin ADB-2012-09 – Use of In-Line Inspection Tools

R.17 Cathodic Protection and Coating Standards

ISO 15589-1 (2015) – Petroleum, petrochemical and natural gas industries – Cathodic protection of pipeline systems – Part 1: On-land pipelines

ISO 21809-1 (2018) – Petroleum and natural gas industries – External coatings for buried or submerged pipelines used in pipeline transportation systems – Part 1: Polyolefin coatings (3-layer PE and 3-layer PP)

ASTM G57 (2020) – Standard Test Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method

ASTM G187 (2018) – Standard Test Method for Measurement of Soil Resistivity Using the Two-Electrode Soil Box Method

R.18 Damage Prevention and One-Call Standards

FCC Title 47 CFR Part 90 – Private Land Mobile Radio Services (one-call system communication standards)

State-Specific One-Call Regulations – e.g., California Government Code §4216; New York Public Service Law §119; Texas Utilities Code Chapter 251

CGA DIRT Report (Annual) – Damage Information Reporting Tool – Analysis of excavation damage incidents

R.19 Survey and Geographic Information System (GIS) Standards

ASCE 38-22 – Standard Guideline for the Collection and Depiction of Existing Subsurface Utility Data (also listed in R.6)

ASPRS (American Society for Photogrammetry and Remote Sensing) Positional Accuracy Standards (2015)

FGDC (Federal Geographic Data Committee) Standards (FGDC-STD-007.3-1998) – Geospatial Positioning Accuracy Standards

R.20 Quality Assurance and Construction Documentation

ISO 9001:2015 – Quality Management Systems – Requirements

ISO 10005:2018 – Quality Management – Guidelines for Quality Plans

ASME NQA-1 (2021) – Quality Assurance Requirements for Nuclear Facility Applications (applicable to QA principles for high-consequence projects)

R.21 Emergency Response and Public Safety

DOT Emergency Response Guidebook (ERG2020) – A Guidebook for First Responders During the Initial Phase of a Dangerous Goods/Hazardous Materials Transportation Incident

NFPA 1600 (2019) – Standard on Continuity, Emergency, and Crisis Management

API Recommended Practice 1173 (2022) – Pipeline Safety Management Systems (also listed in R.4.2)

R.22 Risk Assessment and Management Methodologies

ISO 31000:2018 – Risk Management – Guidelines

API Recommended Practice 580 (2016) – Risk-Based Inspection

IEC 61508 (2010) – Functional Safety of Electrical/Electronic/Programmable Electronic Safety-Related Systems (applicable to SCADA and control system safety)

API RP 1173 (2022) – Pipeline Safety Management Systems (also listed in R.4.2 and R.21)

R.23 Other Industry Guidelines and Technical Papers

INGAA Guidelines for Parallel Construction of Pipelines, Version 1.0 (2011)

INGAA Foundation Report (2014) – Stress Corrosion Cracking Recommended Practices

PRCI Guidelines for the Assessment of Dents on Welds and Associated Anomalies (2015)

Texas Railroad Commission (RRC) Pipeline Safety Rules – 16 TAC Chapter 8

California Public Utilities Commission (CPUC) General Order 112-F (2015) – Requirements for Intrastate Natural Gas Transmission Facilities

Interstate Natural Gas Association of America (INGAA) – Various Technical White Papers and Industry Reports

R.24 Academic and Research Publications

American Society of Mechanical Engineers (ASME) – Journal of Pressure Vessel Technology – Various papers on pipeline integrity and design

Pipeline and Gas Journal – Industry publication; articles on parallel construction case studies

Transportation Research Board (TRB) – NCHRP Reports on Utilities and Pipeline Crossings

National Transportation Safety Board (NTSB) Pipeline Accident Reports – Incident investigations providing lessons learned

Note on References:

The references listed herein represent the primary sources consulted and cited in the development of these Guidelines. In some cases, newer editions or revisions of standards may be available. Users are responsible for verifying that they are using the most current and applicable version of any referenced regulation, code, or standard for their specific project and jurisdiction.

Where a standard is referenced without a specific section or clause, the reference applies broadly to the methodologies, principles, or criteria defined in that document.

Attachment A
Planning and Design Review Meeting(s) Agenda

Overview of Project
Identify **Designated Contact**
Identify parallel segment begin-end points – such as alignment drawings and GPS coordinates
Identify locations where working in close proximity – such as crossings
Availability and accuracy of as-built alignment documentation
Location of existing and proposed appurtenances
Anticipated route
Placement of ROW
Location in ROW (nominal and known exceptions)
Type of easement, exclusive, or open and undefined,
Separation
Anticipated crossings (including directional drills)
Construction methods and practices, including blasting
Identification of potential hazards and emergency response
Existing facility's encroachment and crossing agreements
Existing facility's policy on hand excavation or other excavation techniques around underground facilities
AC/CP and HVAC interference,
Fire/thermal interaction and emergency response,
Geohazards and seismic assessment,
Digital data formats (GIS, 3D models)
Stakeholder and interface management
Schedule
Updating process

Attachment B
Post-Construction Review and Lessons Learned Agenda

What worked?
What didn't work?
Did the guidelines make the project safer?
Did the guidelines make communication more effective?
What improvements or additions would you make to the process?