DACC
DRILLING AND COMPLETION COMMITTEE

IRP 24: Fracture Stimulation

An Industry Recommended Practice (IRP)
for the Canadian Oil and Gas Industry

Volume 24 – 2026 DRAFT April 9, 2026

EDITION: 2
SANCTION DATE: TBD

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CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS Canada's Oil and Natural Gas Producers
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24.0 Preface

24.0.1 Purpose

The purpose of this document is to provide industry supported guidelines to manage subject well integrity, interwellbore communication and surface operations during fracture stimulation operations. It may be used to support the development of internal procedures for safe fracture stimulation practices.

24.0.2 Audience

The intended audience for this IRP includes operators and service companies involved in fracture stimulation operations (e.g., well planning and completions personnel).

24.0.3 Scope and Limitations

The scope for this IRP includes land-based operations in western Canada (British Columbia to Manitoba and territories).

IRP 24 is not intended to replace local jurisdictional regulations. These regulations are referenced throughout the document.

The scope includes the following:

- Recommendations for a risk-based approach to reduce the risk of uncontrolled well events and surface incidents resulting from fracture stimulation operations.

  Note: This IRP does not discuss fracture stimulation well design or subject well integrity regarding well construction.

- A register of potential hazards associated with fracture stimulation operations.

  The document is structured around the Fracture Stimulation Hazard Management Process (FSHMP). The FSHMP is intended to offer a general, high level, iterative planning process typical to most fracture stimulation operations. It was developed collaboratively by a diverse group in the IRP 24 Committee and its working groups. Operator-specific and Service Provider-specific processes may diverge from the FSHMP presented here.

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24.0.4 Revision Process

IRPs are developed by the Drilling and Completions Committee (DACC) with the involvement of both the upstream petroleum industry and relevant regulators. Energy Safety Canada acts as administrator and publisher.

Technical issues brought forward to the DACC, as well as scheduled review dates, can trigger a re-evaluation and review of this IRP in whole or in part. For details on the IRP creation and revisions process, visit the Energy Safety Canada website at www.EnergySafetyCanada.com.

A complete list of revisions can be found in Appendix A.

24.0.5 Sanction

The following organizations have sanctioned this document:

Canadian Association of Oilwell Energy Contractors (CAOEC)

Canadian Association of Petroleum Producers (CAPP)

Enserva

Explorers & Producers Association of Canada (EPAC)

24.0.6 Range of Obligations

Throughout this document the terms 'must', 'shall', 'should', 'may' and 'can' are used as indicated below:

Table 1. Range of Obligation

Term	Usage
Must	A specific or general regulatory and/or legal requirement that must be followed. Statements are bolded for emphasis.
Shall	An accepted industry practice or provision that the reader is obliged to satisfy to comply with this IRP. Statements are bolded for emphasis.
Should	A recommendation or action that is advised.
May	An option or action that is permissible within the limits of the IRP.
Can	Possibility or capability.

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24.0.7 Background

As part of the development of IRP 24, the IRP 24 development committee created the Fracture Stimulation Hazard Management Process (FSHMP) and the Fracture Stimulation Hazard Register as tools to help operators and service providers create or validate their own processes for safety in fracture stimulation operations.

The FSHMP is discussed in detail in 24.3 Fracture Stimulation Hazard Management Process and the hazard register in 24.3.1 Hazard Register.

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24.1 Introduction

This IRP contains recommended practices to help ensure the safety of workers, the public and the environment during fracture stimulation operations. It recommends a risk-based approach using the Fracture Stimulation Hazard Management Process and the IRP 24 Hazard Register to identify considerations for well integrity, interwellbore communication and surface operations.

The subject well integrity section considers downhole fracture stimulation concerns at the subject well for the fracture stimulation operation only. It does not explore fracture stimulation well design or discuss subject well integrity regarding well construction. It includes all downhole equipment up to the fracture treatment iron connection. This chapter offers an assessment methodology to continuously analyze subject well integrity to determine subject well controls that support subject well containment during the fracturing operation.

The Interwellbore Communication section is intended to minimize the risk of uncontrolled well events due to interwellbore communication between an offset well and a subject well as the result of fracture stimulation operations. This section presents a process to determine at-risk offset wells, complete a barrier envelope analysis and adapt well control planning appropriately.

The Surface Operations section assessment includes all above-ground equipment and activities except the wellhead equipment (see 24.5 Subject Well Integrity Assessment). This section determines safety areas, hazard areas, elevated hazard zones, simultaneous operations and special consideration locations. It incorporates the hazard register to identify hazards and reviews considerations for hazard management planning and wellsite execution.

The Fracture Stimulation section outlines the recommended practices for carrying out the fracture stimulation program as planned. It addresses the key activities before, during, and after stimulation to ensure that hazards are effectively managed and operations are executed within established design and control limits. This includes confirming equipment readiness, monitoring operational parameters, and implementing any necessary adjustments to maintain safety and well integrity through the execution phase.

The Continuous Learning section emphasizes the importance of structured post-operation reviews to evaluate performance; document lessons learned and identify opportunities for improvement. It encourages input from all stakeholders and the integration of findings into future planning, design, and hazard management processes. Continuous learning supports a cycle of improvement that strengthens safety performance and operational effectiveness across the industry.

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24.2 Definitions and Regulations

24.2.1 Definitions

Fracture Stimulation A treatment performed above the fracture pressure of the reservoir formation to create a highly conductive flow path between the reservoir and the wellbore.

Induced Seismicity Refers to earthquakes caused or significantly influenced by human activity rather than natural tectonic processes. For further information see resources listed in Appendix H.

24.2.2 Regulations

The following are referenced throughout this IRP.

Regulations for Alberta include the following:

- Directive 008 Surface Casing Depth Requirements
- Directive 009 Casing Cementing Minimum Requirements
- Directive 010 Minimum Casing Design Requirements
- Directive 033 Well Servicing and Completion Operations – Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- Directive 035 Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection
- Directive 058 Oilfield Waste Management Requirements for the Upstream Petroleum Industry
- Directive 059 Well Drilling and Completion Data Filing Requirements
- Directive 060 Upstream Petroleum Industry Flaring, Incinerating, and Flaring
- Directive 083 Hydraulic Fracturing – Subsurface Integrity
- Directive 087 Well Integrity Management

Regulations for British Columbia include the following:

- BCER Defining: Induced Seismicity (2015):
  - Kiskatinaw Seismic Monitoring and Mitigation Area (KSMMA) Special Project Order

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  - The North Montney Seismic Monitoring and Mitigation Area (NMSMMA) Special Project Order
  - Investigation of Observed Seismicity in the Montney Trend (December 2014)
  - Investigation of Observed Seismicity in the Horn River Basin (August 2012)

- Drilling and Production Regulation
  - Section 21 – Fracturing Operations
  - Section 22 – Hydraulic Isolation
  - Section 25 – Inactive or Suspended Wells
  - Section 41 – Venting and Fugitive Emissions, SCVF, Gas Migration
- Dormancy and Shutdown Regulation
  - Section 11 – Annual Work Plan
  - Section 19 - Liability Reduction
- Water Sustainability Act - Section 56 – Decommissioning or deactivating well

Regulations for Manitoba are from the Manitoba Drilling and Production Regulations (The Oil and Gas Act).

- Informational Notice No. 94-5

Regulations for Saskatchewan include the following:

- Directive PNG005: Casing and Cementing Requirements
- Directive PNG008: Disposal and Injection Requirements
- Directive PNG013: Well Data Submission Requirements
- Directive PNG014: Incident Reporting Requirements
- Directive PNG015: Well Abandonment Requirements
- Directive PNG025: Financial Security Requirements
- Directive PNG048: Hydraulic Fracturing Requirements
- Directive S-01: Saskatchewan Upstream Petroleum Industry Storage Standards
- Oil and Gas Conservation Act, 0-2
- Oil and Gas Conservation Regulations, 2012, 0-2 Reg. 6

24.2.3 Regulatory Management Tools

The following table summarizes the jurisdictional regulatory management tools available:

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Table 2. Provincial Electronic Regulatory Management Tools

Province	Tool	Usage and References
Alberta	DDS Digital Data Submission System OneStop	• DDS is the main communication system for completions and hydraulic fracturing. • Main management system associated with suspension-related work and reporting. • Inactive Well License List available on the AER website under the D013 landing page
British Columbia	Kermit or E-Submissions	• See eSubmission User Guide Chapter 4.10 for Hydraulic Fracture Data. • See Well Data Submission Requirements Manual Chapter 2.7.1 for Completion and Workover Reports. • See Hydraulic Fracture FAQ (https://www.bc-er.ca/files/documents/Hydraulic-Fracturing-FAQ.pdf) for more guidance.
Manitoba		• Submit to Petroleum Branch within 30 days (via fax or email).
Saskatchewan	MER Integrated Resources Information System (IRIS)	• See Oil and Gas Conservation Act, Oil and Gas Conservation Regulation (2012), • See PNG 013 Well Data Submission Requirements. • GL20000-01 Hydraulic Fracturing Fluids and Propping Agents Containment and Disposal Guideline

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24.3 Fracture Stimulation Hazard Management Process

The best way to reduce the risk of an uncontrolled well event or surface incident during fracture stimulation operations is through risk-based planning and implementation of control measures that reduce risk to an acceptable level. The IRP 24 Fracture Stimulation Hazard Management Process (FSHMP) includes risk analysis considerations for subject well integrity, interwellbore communication, surface operations, and the activities during the fracture stimulation operations.

With this risk-based approach, IRP 24 uses the concept of “as low as reasonably practicable” (ALARP). ALARP is an approach to reduce risk to a point where risk is acceptable by applying control measures. The balance between risk mitigation and risk exposure is referred to as risk tolerance. The equilibrium point in that balance is ALARP. For more information about ALARP see the CER Safety Plan Guidelines, ISO 31000 Risk Management Guidelines, and CSA Z1002 Occupational Health and Safety Hazard Identification and Elimination and Risk Assessment and Control (see Appendix H: References and Resources).

IRP The owner and/or prime contractor must ensure hazards are eliminated or controlled in consultation with the service company or companies, as they arise during the operation.

IRP Subject well operators shall have a risk assessment model in place to identify risk exposure and tolerance for all planned fracture stimulation operations.

The FSHMP shown in Figure 1 is divided into four columns: Subject Well Integrity Assessment, Interwellbore Communication Assessment, Surface Operations Hazards Assessment, and Fracture Stimulation Execution.

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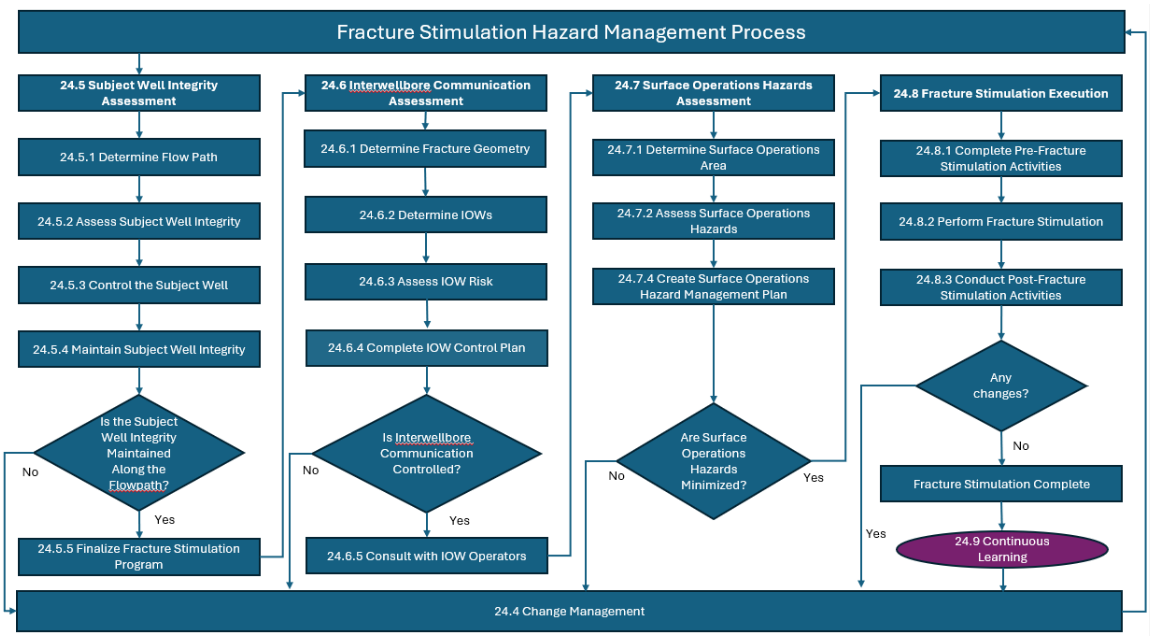
Figure 1. Fracture Stimulation Hazard Management Process



The FSHMP assumes that a fracture stimulation design has been established. Changes may arise throughout the process which may trigger modifications to the fracture stimulation design and/or execution (see 24.4 Change Management). Continuous learning is an important part of the process where valuable lessons are identified during the post-operation review (see 24.9 Continuous Learning).

Note: The IRP 24 FSHMP is not intended to replace existing organizational risk assessment processes and associated risk analysis tools or registers, nor is it intended to provide a complete risk analysis tool for organizations.

24.3.1 Hazard Register

The IRP 24 Hazard Register is a separate document that enables subject well operators to compare industry-known hazard scenarios with their own Operator-specific assessments. It reflects hazard scenarios recognized by industry at the time of this IRP's publication.

The purpose of the IRP 24 Hazard Register is as follows:

- Provide a shared location for industry-identified hazard scenarios.
- Facilitate operational planning by providing potential options to minimize risk and determine appropriate controls.
- Provide a mechanism for contingency planning and development of site-specific control measures.

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The IRP 24 Hazard Register is a living document to be updated regularly by industry experts. As new hazard scenarios arise and new controls or mitigations are developed, they may be documented in the IRP 24 Hazard Register for industry-wide use. All organizations are encouraged to share lessons learned as additions to the IRP 24 Hazard Register.

> **Note:** The IRP 24 Hazard Register is not an exhaustive list. Operation and site-specific hazards need to be included and evaluated during planning.

The IRP 24 Hazard Register and the submission template for additions are available for download with IRP 24 on the Energy Safety Canada website.

IRP The subject well operator shall use the IRP 24 Hazard Register or integrate these hazard scenarios into existing organizational risk assessment processes to identify all risk assessment considerations.

24.3.2 Planning Challenges

24.3.2.1 Lease Spacing

Facility and equipment spacing is best determined early in the planning stages. Refer to IRP 20: Wellsite Design Spacing Recommendations for general guidance.

Consider the following when planning fracture stimulation operations:

- Locate fracture stimulation operations on the lease and assess whether the lease can accommodate the planned operation.
- Ensure adequate spacing between operations and between existing wells.

Spacing requirements may necessitate modifications to subject well parameters, the fracture stimulation program or, where possible, the lease layout.

24.3.2.2 Simultaneous Operations

Multi-well and multi-stage fracture programs increase the likelihood of simultaneous operations (SimOps) on the lease. Simultaneous operations are any activities occurring in proximity to the subject well that are not part of the current fracture stimulation operation.

Simultaneous on-lease downhole operations expected during fracture stimulation are classified as Identified Offset Wells (IOWs) and are assessed through the IOW Risk Assessment (see 24.6.3 Assess IOW Risk). For information on surface SimOps within hazard areas, see 24.7.1.2 Identify Simultaneous Operations.

IRP The subject well operator shall identify and plan for potential simultaneous operations during the planning stages.

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24.3.2.3 Shallow Well Fracture Stimulation

Fracture stimulation operations near the top of bedrock or base of groundwater may result in fluid releases to the surface, contamination of non-saline aquifers, and breaches of the containment mechanism leading to loss of reserves.

IRP Local jurisdictional regulations for hydraulic fracturing must be followed to prevent surface impacts, contamination of non-saline aquifers, and loss of reserves when fracturing near the top of bedrock.

24.3.2.4 Monitoring and Reporting Induced Seismicity

Seismicity refers to the geographic and historical distribution of earthquakes. Induced seismicity (IS) is a seismic event resulting from human activity and can be caused by industries such as mining, dam impoundment, CO_2 sequestration, geothermal activities, and hydrocarbon development (e.g., hydraulic fracturing, waste disposal or pressure maintenance, and subsidence).

IRP Prior to conducting fracture stimulation activities in areas where there is a risk of induced seismicity, the subject well operator shall conduct a risk assessment that includes:

- Identification of areas with higher seismic risk from previous events, site amplification potential, and surface risks (e.g., population centers, critical infrastructure, offset key assets).
- Identification of faults from available published data and/or seismic reviews.
- Evaluation of stress magnitudes and directions (geomechanics) using published or proprietary sources.
- Communication with IOW operators and local residents to keep them informed of potential induced seismicity activities in the area.

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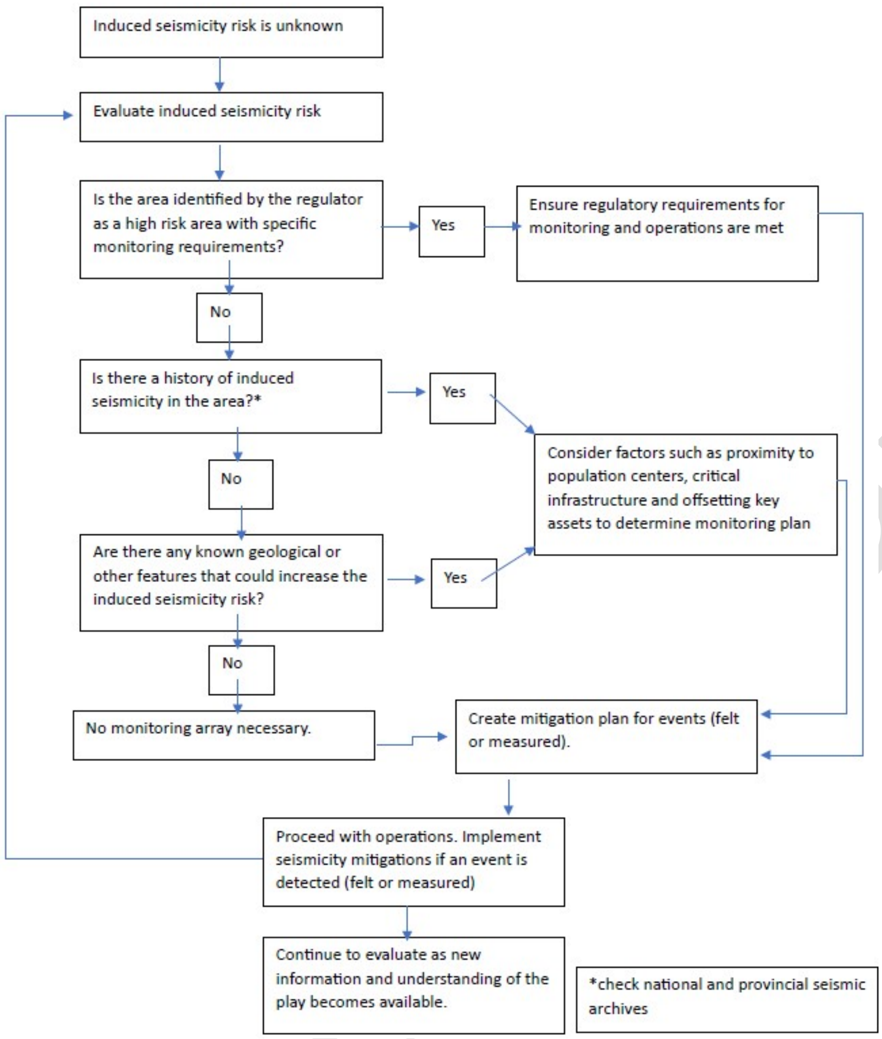
Figure 2. Induced Seismicity Risk Assessment Process



IRP **During fracture stimulation activities the subject well operator and service company or companies must follow local jurisdictional requirements for seismic monitoring. Where monitoring is required, monitor for low-level seismic events as a tool for mitigation efforts and as an early warning for potential larger events. Monitoring requirements will vary by region.**

Subject well operators and service companies may consider using a traffic light protocol to define thresholds for stopping work (i.e., a red light indicates a certain magnitude at which fracture activities are immediately suspended and the regulator is directly contacted).

IRP Subject well operators and service companies should take actions to mitigate the potential for induced seismic events as much as possible. In no specific order, these actions may include rest periods, adjusting stages, more perforation clusters, less sand, lower fluid volume, reduced pumping rate, skipping stages, changing fluid viscosity, and adjusting flowback.

IRP **Subject well operators must complete post-fracturing induced seismicity assessments to capture induced seismicity patterns and attributes as required by local jurisdictional regulations. It is recommended to share lessons learned with industry groups.**

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24.4 Change Management

Throughout the FSHMP, changes that arise need to be assessed and managed. The questions posed in the light blue diamonds on the FSHMP figure may trigger change management activities.

During planning and execution of fracture stimulation, plans may change.

IRP When operational changes arise, subject well integrity, interwellbore communication, and surface operations hazards should be re-evaluated to manage risks.

Examples of change management to safely resume include:

Modifying subject well controls as necessary (see 24.5.3 Control the Subject Well and 25.5 Finalize Fracture Stimulation Program), such as:

- Frac stimulation changes
  - Pumping rates, pressures, volumes, and duration
  - Changing the location of fracture initiation points in subject well
  - Adjusting and/or blanking-off fracture stimulation stages
- Pumping conveyance method
- Downhole tool selection
- Surface equipment changes
- Casing design modifications (e.g., installing Tieback)

Interwellbore Communication Change Management

To mitigate risks related to interwellbore communication, the following adjustments may be necessary:

- Modifying the subject well parameters as mentioned above and 24.5.5 Finalize Fracture Stimulation Program).
- Adjusting the IOW Control Plan (see 24.6.4 Complete IOW Well Control Plan).

If the subject well operator is confident that the planned controls and mitigations are within their risk tolerance and will effectively minimize the risk of interwellbore communication causing a loss of well control at an IOW, they may initiate consultation with at-risk IOW operators.

IRP If the subject well operator is uncertain about the effectiveness of the planned controls, they should

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- re-evaluate assumptions and seek additional information
- consult with industry peers
- modify the fracture stimulation timing or design if needed

In situations where the at-risk IOW well control plan is deemed insufficient to minimize risk, it may be necessary to modify the fracture stimulation design and program accordingly.

Surface Operations Change Management

IRP When the risks of surface operational hazards are not tolerable or changes to operational plans occur, the following actions should be taken:

- Conduct a Surface Operations Hazard Assessment in accordance with IRP 24's Surface Operations Hazard Management Assessment (see Figure 12. Surface Operations Hazard Management Assessment in the FSHMP).
- Revise the Fracture Stimulation Program as necessary (see 24.5.5 Finalize Fracture Stimulation Program).
- Modify the schedule to minimize simultaneous operations (see 24.7.1.2 Identify Simultaneous Operations).

It is imperative to regularly assess the active operations area, and to communicate changes to designated areas, zones, and controls to all affected parties when tasks or operations change.

Fracture Stimulation Execution Change Management

IRP Once fracture operations begin, any changes that arise must be assessed for risk and mitigated to as low as reasonably practicable. See Appendix B Case Studies for examples.

IRP Using all available data, the Subject Well Operator shall apply engineering judgement to extrapolate x_f for any changes to the planned fracture stimulation of the subject well.

> **Note:** Changing fracture design parameters may require changes to the FPZ.

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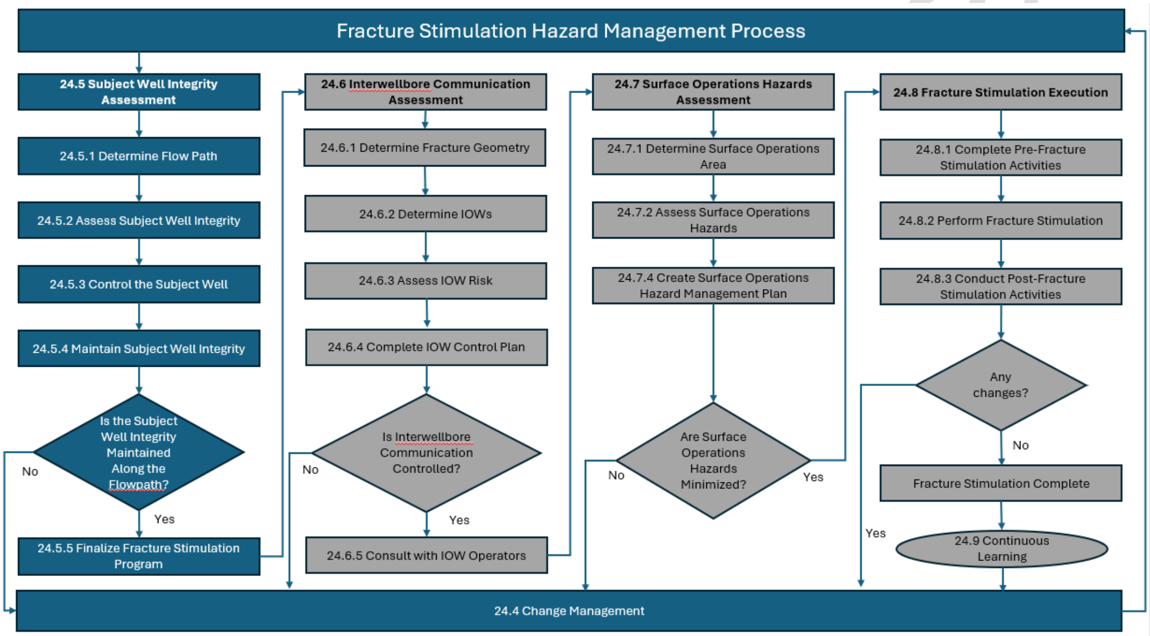
24.5 Subject Well Integrity Assessment

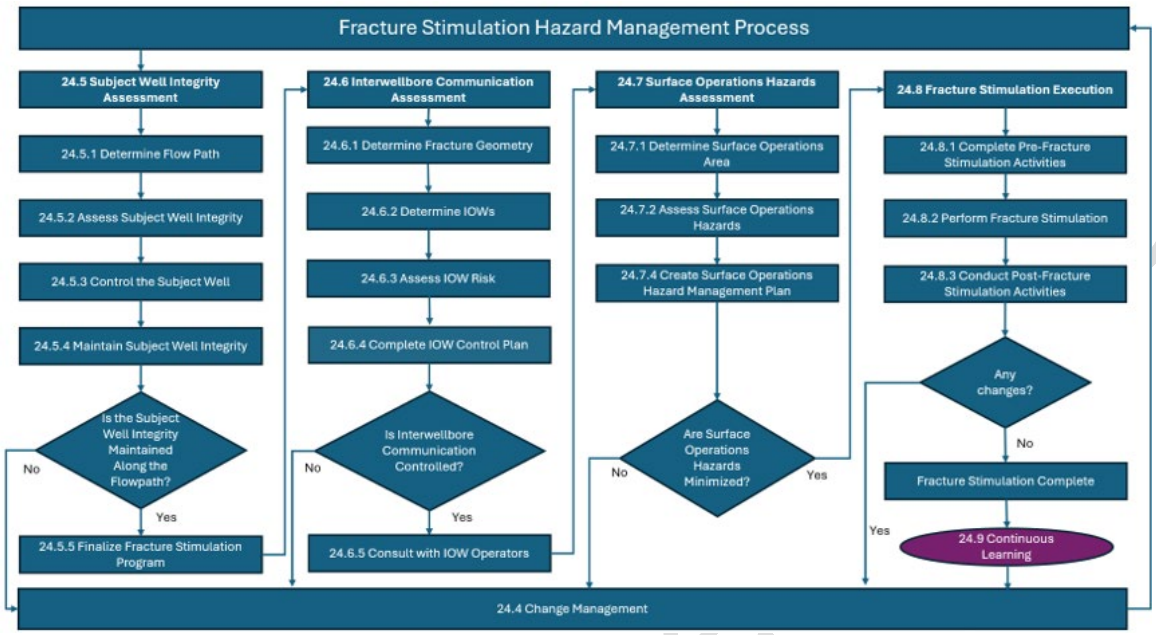
The subject well integrity assessment is the first stage of the overall Fracture Stimulation Hazard Management Process as shown in Figure 3.

Figure 3. Subject Well Integrity Assessment in the FSHMP



The assessment, illustrated in Figure 3, involves determining the flow path, evaluating well integrity by analyzing the subject well barrier envelope and its limitations, controlling the subject well, and ensuring ongoing integrity. If integrity is maintained along the flow path, the fracture stimulation program can proceed to the Interwellbore Communication Assessment. If integrity cannot be maintained, the change management process in 24.4. Change Management needs to be followed.

Figure 4. Subject Well Integrity Assessment



A subject well with sound integrity ensures fracture placement reaches the intended target formation while containing fluids associated with the fracturing operation within the wellbore. Subject wells intended for fracture stimulation often have temporary equipment installed (e.g., wellhead isolation equipment) during the completion phase to contain and manage high-pressure stimulation operations. Typically, the highest internal pressures a subject well experiences occur during fracture stimulation, which may be the only time the well encounters such elevated pressures.

In addition to pressure, other fracture stimulation factors can compromise subject well integrity. Controls are implemented to maintain integrity during fracture stimulation operations (see 24.5.3 Control the Subject Well). Recommendations for cementing wells are provided in IRP 25: Primary and Remedial Cementing Guidelines.

The two principal means for minimizing the risk of losing subject well integrity are

1. adjusting the fracture stimulation design or
2. designing or modifying subject well controls.

IRP **The subject well operator shall minimize the risk of fracture stimulation operations causing an uncontrolled well event at the subject well.**

IRP **If an uncontrolled well event occurs or subject well integrity fails, the subject well operator must notify the appropriate authority in accordance with local jurisdictional regulations.**

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Subject well integrity, as addressed in this section, considers downhole fracture stimulation concerns for the subject well during the fracture stimulation operation only. It includes all downhole equipment up to the fracture treatment iron connection. The relationship between fracture stimulation design and the barrier envelope's limitations are evaluated to determine whether to adjust subject well controls or modify the fracture stimulation design. The fracturing iron is covered in 24.6 Surface Operations.

24.5.1 Determine Flow Path

Using the preliminary fracture design, determine the expected flow path for fracturing fluids (casing, tubing, liner, coiled tubing, an annulus or a combination). The flow path is the conduit that delivers fracturing fluids from the surface to the intended target formation.

Once the flow path is identified, determine the barrier envelope that contains it. This barrier envelope will be evaluated in the subsequent subject well integrity assessment.

24.5.2 Assess Subject Well Integrity

Subject well integrity assessment provides the framework for evaluating the current subject well barrier envelope expected to receive and contain fracturing fluids. The subject well barrier envelope consists of one or more barrier elements that prevent fluids from flowing unintentionally from the formation into the wellbore, into another formation, or to the external environment.

A barrier element is an individual equipment component or object that, in combination with others, forms a barrier envelope. A barrier element alone cannot prevent flow through itself. A barrier envelope designed to contain fracturing fluids will maintain subject well integrity throughout the fracture stimulation operation.

Fracture stimulation operations may occur on new or existing wells. In both cases, a well barrier envelope is in place before fracture operations begin but may not be specifically designed to contain the planned fracture stimulation program. Therefore, the existing barrier envelope is assessed to determine its ability to withstand the planned fracture stimulation operation and whether mitigation measures are required.

An effective subject well integrity assessment first determines the expected flow path for the fracturing fluids. It then analyzes incompatibility between barrier elements and fracture stimulation factors, cross-referencing with the IRP 24 Hazard Register. The final step evaluates the collective limitations of barrier elements as an envelope against fracture stimulation factors and site-specific hazard scenarios.

Fracture stimulation subject well integrity assessment is organized into four parts:

1. Subject Well barrier envelope analysis
2. Fracture stimulation factors
3. IRP 24 Hazard Register

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4. Barrier envelope limitations

24.5.2.1 Analyze Subject Well Barrier Envelope

The barrier envelope analysis evaluates each barrier element along the expected flow path to determine the barrier envelope Adjusted Maximum Pressure (AMP). The barrier envelope AMP is set by the lowest AMP of all barrier elements in the envelope(s).

IRP The subject well operator shall determine the subject well barrier envelope(s) AMP. See Appendix D: Casing Burst and Collapse Considerations, for factors to consider.

IRP Subject well barrier envelope analysis should include the following steps:

- Identify the envelope(s) (primary and secondary, if applicable). A barrier envelope consists of all barrier elements that work together to contain fracture fluids. These may be illustrated on a barrier schematic (see Appendix C for examples through casing and fracture string).
- Determine the AMP for each barrier element. Review design and installation. Calculate the AMP by starting with the Original Equipment Manufacturer (OEM) pressure rating and adjusting for service factors affecting barrier performance (see Appendix D: Casing Burst and Collapse Considerations for burst and collapse considerations and AMP Calculations.) This adjustment is at the subject well operator's discretion, aligns with their risk tolerance, and meets regulatory requirements such as AER Directive 010 minimum casing design requirements.
- Tri-axial load modelling should be considered for initial casing design and when well design assumptions change (e.g., changes in casing design or fracture design). See Appendix D: Casing Burst and Collapse Considerations for tri-axial load model examples.
- Establish the envelope AMP by identifying the lowest barrier element AMP. Compare this value against fracture stimulation factors and the Hazard Register to determine barrier envelope limitations. See Appendix D: Casing Burst and Collapse Considerations for suggested calculations.
- Assess groundwater protection at the subject well. Refer to IRP 25: Primary Cementing.

  Note: If the barrier analysis identifies groundwater protection concerns that cannot be resolved by upgrading the barrier envelope, the fracture stimulation design is revisited. Baseline water well testing may be considered prior to fracture stimulation.

24.5.2.2 Identify Fracture Stimulation Factors

Several factors can influence subject well integrity during fracture stimulation operations. These factors can be grouped into geological conditions, fracture stimulation parameters, and potential failure modes.

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IRP The subject well operator shall identify fracture stimulation factors that could compromise subject well barrier envelope(s).

Subject well barrier fracture stimulation factors may include, but are not limited to, the following:

- Geological conditions
  - Fault analysis
  - Induced seismicity (e.g., prior induced seismicity)
  - High permeability streaks (natural fractures, conglomerate intervals)
  - Bounding layers
  - Reservoir parameters (e.g., pressure, temperature, H_2S, lithology, depth)
- Stimulation parameters
  - Multistage method (e.g., ball drop, fracture sleeves, plug-and-perforate)
  - Fluid (e.g., system chemistry, type, volumes)
  - Proppant (e.g., type, size, concentrations, volumes)
  - Pumping (e.g., pressures, rates, schedule)
  - Diverters (e.g., ball sealers, polylactic acid (PLA), pods)
  - Maximum burst pressure and maximum collapse pressure (see Appendix D: Casing Burst and Collapse Considerations for suggested calculations)
- Potential failure modes
  - Erosion
  - Corrosion
  - Sulphide stress cracking (SSC) (e.g., unacceptable axial or circumferential stresses in material exposed to sour fluids)
  - Excessive cyclic loading
  - Thermal loading
  - Mechanical loading (i.e., tri-axial stress)
  - Internal and external pressures
  - Inadequate cement hydraulic isolation
  - Out-of-specification well construction practices (e.g., connection over-doping, over-torque, under-torque)
  - Faulting-induced casing damage (see 24.3.2.4 Monitoring and Reporting Induced Seismicity)

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24.5.2.3 Reference Related Resources

A review of relevant IRPs and guidelines may provide additional guidance. See the following:

- IRP 02: Completing and Servicing Sour Wells
- IRP 05: Minimum Wellhead Requirements
- IRP 25: Primary Cementing
- IRP 26: Wellbore Remediation

24.5.2.4 Determine Barrier Envelope Limitations

Barrier envelope limitations are based on the analysis of the barrier envelope AMP, fracture stimulation factors, and wellbore-specific hazards.

Barrier envelope limitations may include, but not be limited to, the following:

- Expected pumping pressures greater than the barrier envelope AMP
- Potential failure modes (see 24.5.2.2 Identify Fracture Stimulation Factors)

IRP The subject well operator shall determine the limitations of the barrier envelope(s).

24.5.3 Control the Subject Well

The Subject Well Integrity Assessment identifies the limitations of the existing subject well barrier envelope(s). Subject well control establishes mitigations to ensure these limits are not operationally exceeded. These control measures ultimately ensure that fracture placement reaches the intended target formation while maintaining subject well integrity.

IRP The subject well operator shall implement subject well control practices based on the findings of the Subject Well Integrity Assessment.

IRP If an uncontrolled release event occurs the subject well licensee's Emergency Response Plan (ERP) shall be invoked. Hydraulic fracturing operations shall be immediately shut down until the release is contained and operations can safely resume.

Operational practices to maintain subject well containment are selected according to the specific subject well barrier envelope limitations. Because each well is unique, a standardized list of strategies and practices is impractical. However, a common approach is to compare barrier envelope AMPs to the fracture stimulation program to confirm compatibility.

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24.5.3.1 Determine if No Action Required

If the barrier envelope(s) limitation is deemed sufficient, no additional actions or monitoring may be required during the fracture stimulation operation.

24.5.3.2 Determine if Monitoring Required

The subject well operator may determine that modifications to the barrier envelope can be triggered by closely monitoring pressure and rate data during fracture operations. Monitoring may be selected as a well control practice when the subject well operator and service company or companies agree that barrier limitations can be addressed during the operation.

24.5.3.3 Upgrade Barrier Envelope if Needed

When a primary barrier envelope AMP does not meet the fracture stimulation program (i.e., maximum treatment pressure), the barrier envelope is upgraded. For a new drill, the subject well operator may modify the casing design to a higher OEM specification. If upgrading the barrier envelope is not possible, the subject well operator may isolate the casing with another barrier element (e.g., install a fracture string or use other conveyance methods to create an artificial or mechanical barrier), or adjust the fracture stimulation program so the existing primary barrier envelope can maintain containment (e.g., reduce pump rates to lower maximum treating pressure).

24.5.4 Maintain Subject Well Integrity

Once the subject well control practices are established, review the plan to confirm that integrity is maintained along the expected fracture fluid flow path. During this evaluation consider the flow path, barrier limitations, and current well control measures. Together, do these elements provide confidence that subject well integrity will be protected during stimulation? This aligns with the decision diamond in Figure 3 Subject Well Integrity Assessment in the FSHMP (see 24.5 Subject Well Integrity Assessment).

If the subject well operator is confident that planned controls and mitigations are within their risk tolerance and will minimize the risk of an uncontrolled well event, the fracture stimulation program may be finalized, and the process can proceed to interwellbore communication assessments

If there is uncertainty that the planned controls will sufficiently minimize risk, the subject well operator will identify and address the cause. This may involve

- revising the expected fracture fluid flow path (24.5.1 Determine Flow Path),
- revisiting barrier envelope analysis (24.5.2.1 Analyze Subject Well Barrier Envelope),
- reconsidering barrier envelope limitations (24.5.2.4 Determine Barrier Envelope Limitations),

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- re-establishing subject well control practices (24.5.3 Control the Subject Well)
- modifying simultaneous operations timing and/or
- revisiting fracture stimulation design.

The fracture stimulation program may only be finalized once the subject well operator is confident the risk of an uncontrolled well event has been mitigated within their risk tolerance.

24.5.5 Finalize Fracture Stimulation Program

The fracture stimulation program defines the procedures and requirements to meet the subject well fracture stimulation design. It includes, but is not limited to, the following parameters:

- Flow path configuration (e.g., surface and downhole)
- Target formation and depths
- Wellbore design
- Pressures
- Base fluid types
- Chemicals
- Fluid rheology
- Proppant type, size, concentration, and tonnage
- Rates
- Volumes
- Equipment

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24.6 Interwellbore Communication Assessment

The interwellbore communication assessment is the second part of the FSHMP (see Figure 5).

Figure 5. Interwellbore Communication in the FSHMP

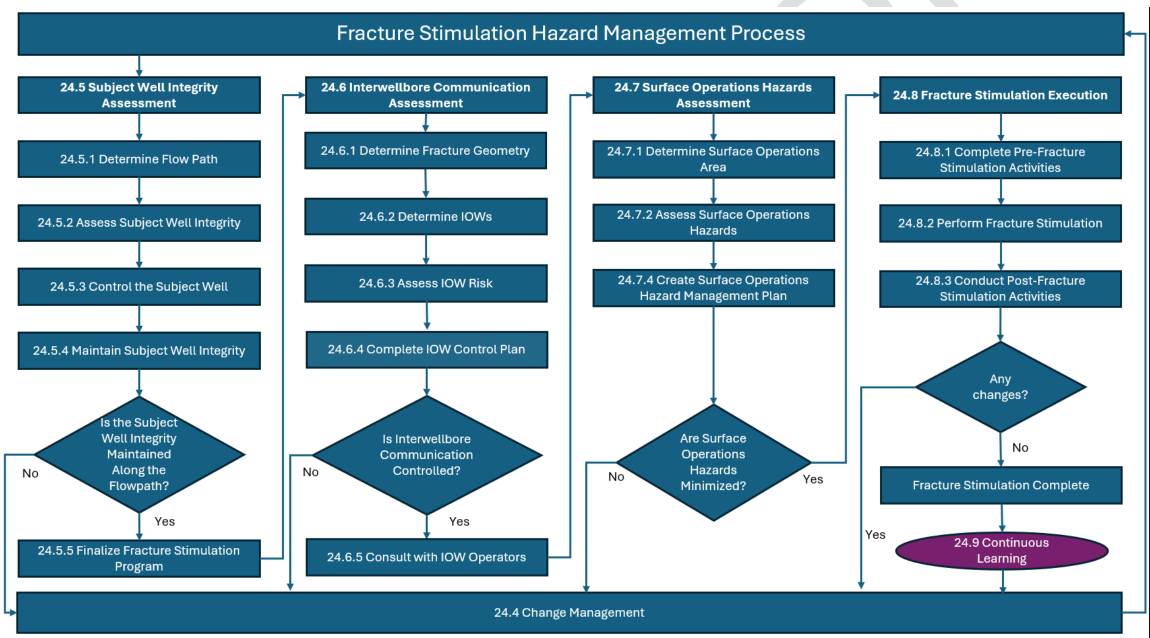

Figure 6 outlines the assessment process which involves

- identifying offset wells by mapping the fracture planning zone,
- evaluating IOW risk through barrier and proximity analysis,
- identifying active or pending downhole operations and
- completing a control plan to mitigate risks.

If interwellbore communication is effectively controlled, the surface operations hazards assessment can proceed. Otherwise, changes need to be managed before moving to the next stage of the FSHMP.

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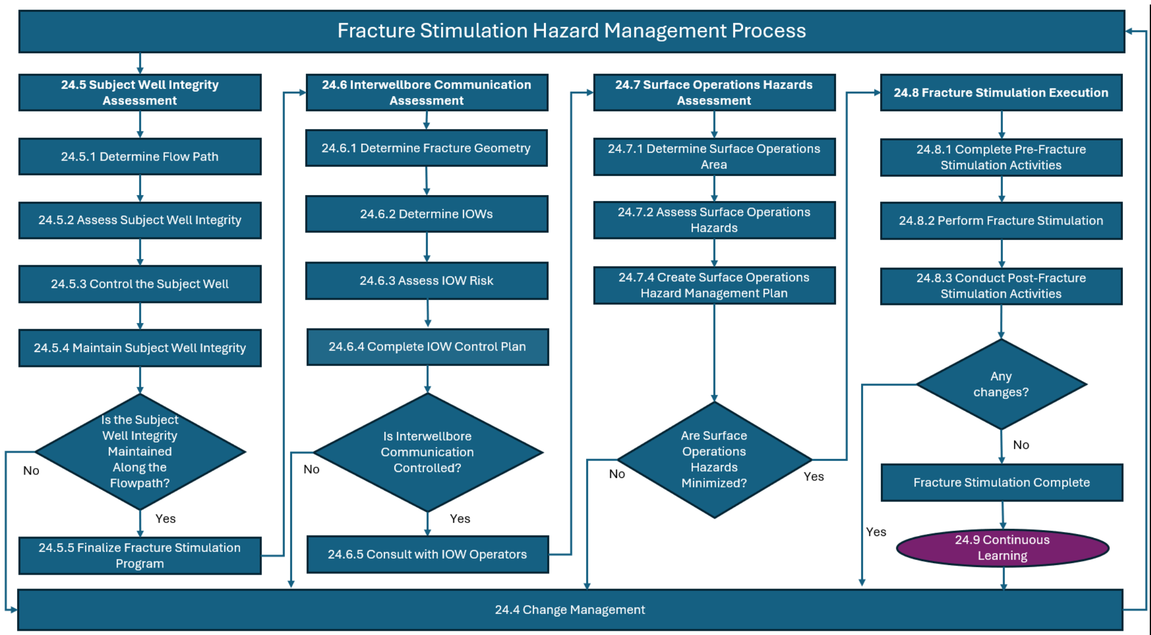
Figure 6. Interwellbore Communication Hazard Management



The interwellbore communication assessment is intended to minimize the risk of uncontrolled well events caused by fluid and/or pressure communication between an offset well and a subject well during fracture stimulation operations. This section provides a process to determine at-risk offset wells, complete a barrier envelope analysis at an offset well, and adapt well control planning for both planned and unplanned interwellbore communication events.

Interwellbore communication can result in an uncontrolled well event.

Typically, the highest pressures a subject well experiences, occur during fracture stimulation and may be the only time the well is exposed to such elevated pressures. Temporary high-pressure equipment is often installed for these operations. Offset wells are generally designed for the production phase and may require additional risk-reduction measures if interwellbore communication is possible.

IRP **The subject well operator shall be responsible for minimizing the risk of interwellbore communication causing an uncontrolled well event at an identified offset well during fracture stimulation operations at the subject well.**

IRP **If an uncontrolled well event at an identified offset well (IOW) occurs, the subject well operator must comply with local jurisdictional regulations.**

IRP **If an uncontrolled well event at an IOW occurs, the subject well operator shall notify the IOW operator in accordance with the Well Control Plan. See 24.6.4 Complete IOW Well Control Plan.**

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IRP If an uncontrolled release event occurs at an IOW, the subject well licensee's Emergency Response Plan (ERP) shall be invoked, and the IOW operator shall be notified to invoke their ERP in accordance with local jurisdictional regulations. Hydraulic fracturing operations shall be immediately shut down until the release is contained and operations can safely resume.

There are two principal means for minimizing the risk of interwellbore communication or uncontrolled well events at an IOW:

1. Adjusting the subject well's parameters (see 24.4 Change Management) and
2. Developing an appropriate IOW Control Plan.

24.6.1 Determine Fracture Geometry

Understanding fracture geometry is critical for determining the fracture planning zone and assessing at-risk IOWs. The two methods below can be used to determine fracture geometry, though they are not the only options.

IRP The subject well operator should update and calibrate their fracture geometry models on an ongoing basis as new information becomes available.

Method 1–Fracture Model and/or Simulation

Determine a fracture half-length (x_f) and fracture height (z_f) for all proposed fracture treatments at the subject well. Creating a fracture model and/or simulation is one method to establish x_f (See Appendix E: Modelling Fracture Geometry).

Note: Historical data can help calibrate the fracture model.

Method 2–Historical Review

Perform a historical review of completion practices and collected data within the formation and geographical area.

Inputs to consider include

- Stimulation design
    - Proppant type and amount
    - Fluid rheology
    - Total fluid rate and volume
    - Total number of stages
    - Completion system and design
    - Wellbore spacing

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- Communication events
    - Fracture design and distance of the communication event
    - Fracture azimuth during the communication event
    - Communication events outside of the target zone (see Appendix B: Case Studies)
- Other data sources
    - Tracer data
    - Microseismic data
    - Geological data (e.g., fault mapping)
    - Recent reservoir pressure data (e.g., depletion, secondary recovery methods)
    - Isolation failures causing fracture reactivation (e.g., plug slips)
    - Data shared by other operators or service companies active in the area

If sufficient historical review data is available to justify x_f and z_f, use these parameters to create an FPZ as outlined in section 24.6.2.1 Identify Fracture Planning Zone.

IRP In the absence of historical data, larger safety factors to fracture dimension estimates should be applied.

IRP Fracture geometry assumptions should be refined through continuous improvement.

IRP Any changes to fracture treatment design should trigger a re-evaluation of fracture geometry.

24.6.2 Determine Identified Offset Wells

IOWs are all offset wells located within the FPZ (see 24.6.2.1 Identify Fracture Planning Zone) and any wells classified as Special Consideration Wells (SCW) (see 24.6.2.4 Identify Special Consideration Wells).

IOWs include, but are not limited to the following:

- Licensed but not yet spud
- Drilling
- Completing or servicing
- Cased and standing (e.g., drilled but without a wellhead installed)
- Open hole
- Producing or injection

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- Shut-in or suspended
- Abandoned in any form (e.g., cut and capped)
- Orphaned (no legally responsible or financially able operating company)
- Active operations (manned or unmanned)
- Disposal wells

IRP The subject well operator shall determine the set of IOWs relevant to the subject well.

24.6.2.1 Identify Fracture Planning Zone (FPZ)

The FPZ defines a two-dimensional space around the subject well within which any offset wells require a risk assessment.

To create an FPZ, the fracture half length (x_f) is determined. This value is based on the potential for a planar, single-wing hydraulic fracture.

The fracture half-length (x_f) is the lateral distance in the horizontal plane, perpendicular from the subject well, to the outer tip of a fracture created during fracture stimulation operations. It represents the maximum extent of subsurface influence from an induced fracture.

IRP The subject well operator shall determine fracture geometry using supporting methodology and data to map the FPZ.

24.6.2.2 Map the Fracture Planning Zone (FPZ)

FPZ mapping identifies wells within the FPZ. Mapping requires the fracture half-length value (x_f) and the well path. The well path may be proposed or actual; however, if a proposed path is used, the FPZ map may need to be updated after drilling to include any newly identified IOWs (see 24.6 Interwellbore Communication Assessment). Using proposed well paths can help facilitate timely communication between subject well operators and IOW operators.

IRP. Using the longest x_f determined, the Subject Well Operator shall draw the FPZ outer boundary of to a distance equal to twice the fracture half-length ($2x_f$) from the wellbore around the plan view of the well (see Figure 7).

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Figure 7. Horizontal Well – Plan View

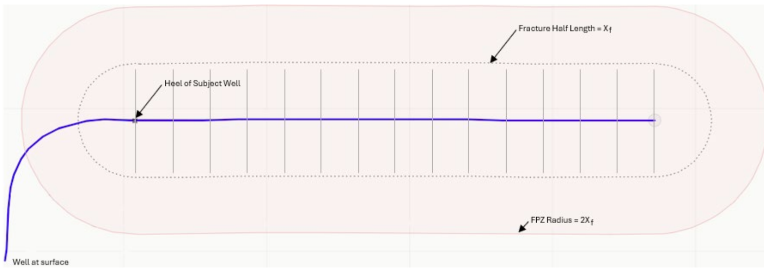

Figure 8. Horizontal View Including Zf

Figure 9. Vertical Well – Plan View

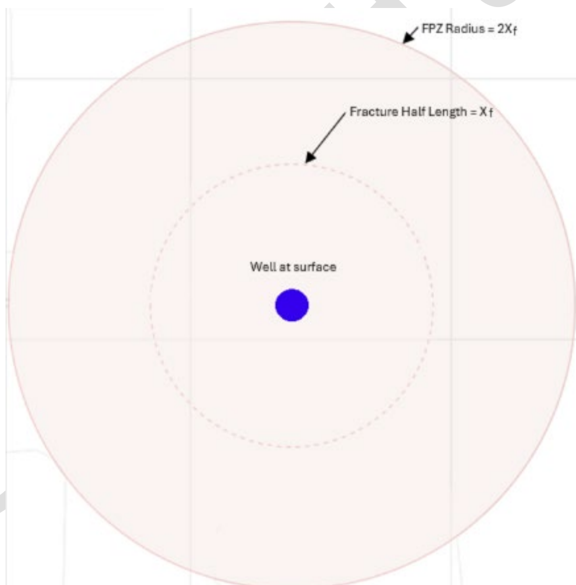

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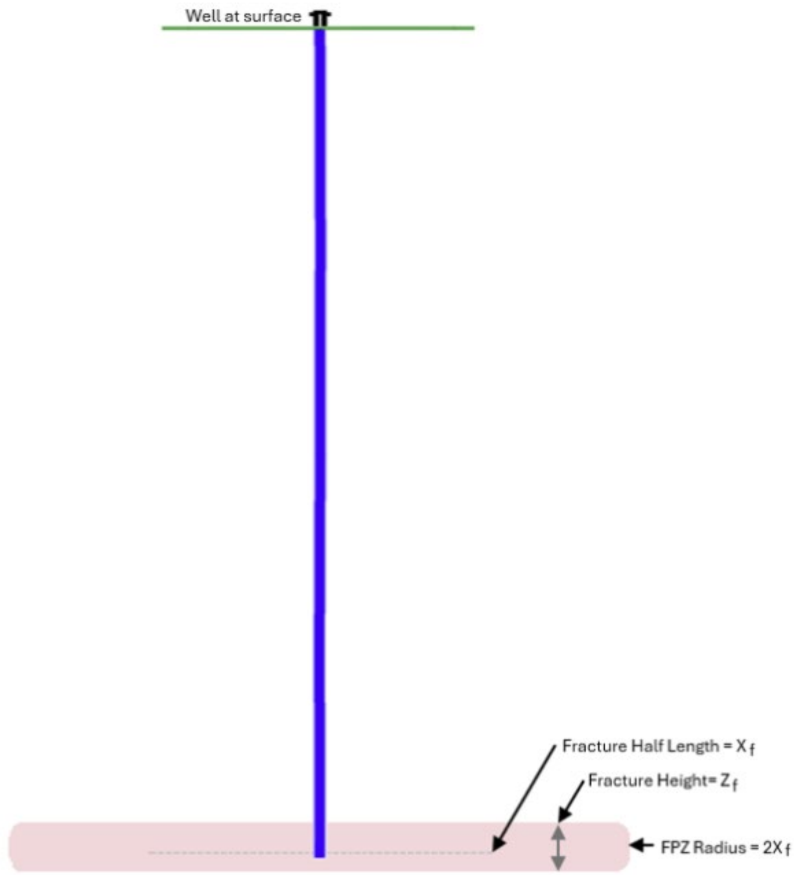
Figure 10. Vertical Well Horizontal View Including Zf



24.6.2.3 Identify IOWs Within the Fracture Planning Zone

Once the FPZ is determined, identify and map each offset well that intersects it. Classify these wells as FPZ wells and record their vertical and horizontal proximity to the subject well.

IRP The subject well operator shall identify and map all FPZ wells.

24.6.2.4 Identify Special Consideration Wells

Special Consideration Well (SCW) determination allows individual wells of concern to be included in the IOW Risk Assessment without expanding the FPZ. SCWs are offset wells beyond the FPZ that have unique circumstances which may put the well at risk and therefore require risk assessment.

Offset wells beyond the FPZ may be classified as SCWs if they meet some or all the following criteria:

- Historical experience indicating elevated risk
- Estimation uncertainty when determining the FPZ (see Appendix E: Modeling Fracture Half-Length and Fracture Height)

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- Fracture azimuth (consider surface and subsurface monitoring data, such as microseismic)
- Geology (e.g., regions prone to natural faults and fractures
- Reservoir conditions (e.g., depletion, overpressure)
- Age and condition of the offset wellbore
- Freshwater or non-saline well
- Saline water source well
- Potential for pressure communication
- Wells with fracture half-lengths that may intersect the FPZ
- Wells being drilled with planned trajectories that intersect the FPZ (not necessarily during fracture operations)
- Disposal wells (e.g., Salt water, acid gas, water injection)
- Geothermal
- Carbon capture utilization and storage (CCUS)
- Brine-hosted minerals
- Gas storage
- Mineshaft, cave, non-energy wellbore
- Operators requesting notification of nearby fracturing activities
- Other horizons with potential to be fractured into

IRP The subject well operator shall identify SCWs beyond the FPZ to assess the risk of long-distance communication.

24.6.3 Assess IOW Risk

Once a clear set of IOWs is identified (see 24.6.2 Determine Identified Offset Wells), the IOW risk assessment establishes the framework for developing IOW Well Control Plans.

Effective interwellbore communication risk assessment involves the following five steps:

1. Step 1–Determine at-risk IOWs.
2. Step 2–Complete barrier analyses for at-risk IOWs only.
3. Step 3–Assess IOW proximity risk.
4. Step 4–Identify IOWs with active downhole operations.
5. Step 5–Consider additional hazards specific to your operations.

Note: The IRP 24 Hazard Register may be used to consider additional risks.

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24.6.3.1 Step 1–Determine At-risk IOWs

The subject well operator uses a risk-based approach to classify wells as at-risk or minimal risk.

A well is considered at risk if

- the subject well fracture geometry indicates potential for the planned fracture to communicate with the IOW. Consider fracture height (z_f) when assessing communication risk (see 24.6.1 Determine Fracture Geometry),
- specific considerations that may over or underestimate z_f are outlined in Appendix E,
- in the absence of adequate historical data, wells located within 200 m above the top or below the bottom of the target zone, or within two times z_f (whichever is greater), are classified as at-risk,
- the IOW could communicate with the subject well via faulting or other geological features,
- the IOW terminates, or has hydraulic fracture geometry, near the subject well FPZ and
- the IOW has active work such as drilling, workover, or abandonment.

A well is considered minimal risk if

- based on the subject well operator's risk tolerance, it does not require a barrier analysis or any actions during fracture stimulation operations or
- it is not determined to be at-risk, and the rationale for this classification is documented (see 24.6.4.1 Identify IOW Well Control Practices).

IRP The subject well operator shall notify all IOW owners within the FPZ of the planned fracture activity at least within 30 days prior to operations, to allow for thorough review.

IRP The subject well operator shall identify at-risk IOWs from the complete set of IOWs as per Step 1.

24.6.3.2 Step 2–Complete At-Risk IOW Barrier Analysis per Jurisdictional Requirements

IRP Once notified, existing IOW operators shall conduct a risk assessment and barrier envelope analysis on each at-risk offset well.

IRP If no response is received, or if no IOW operator exists, the subject well operator shall ensure IOW integrity by completing a barrier envelope analysis. If this cannot be completed, the subject well operator shall

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assess and mitigate risk through fracture stimulation planning and execution.

A barrier envelope analysis evaluates well integrity for well control planning. It

- assesses potential interwellbore communication flow paths,
- identifies at-risk IOW barrier envelope(s) and associated barrier elements, and
- determines an Adjusted Maximum Pressure (AMP) for each barrier element.

The following definitions specific to interwellbore communication at an offset well:

- **IOW barrier envelope:** All barrier elements on a possible communication flow path that depend on each other to prevent or control flow.
- **IOW barrier element:** An individual equipment component within a barrier envelope (e.g., casing, cement, casing hanger, packers, tubing hanger, tubing, wellhead valves, tubing plug).
- **Adjusted Maximum Pressure:** Determined by analyzing the original equipment specification, age, and service history for each barrier element.
- **Primary barrier envelope:** The first line of defense for preventing or controlling flow.
- **Secondary barrier envelope:** An additional layer of risk reduction if the primary barrier fails or is deemed too high-risk.

IRP A barrier envelope analysis should include the following:

- Evaluate interwellbore communication flow path scenarios (see Figure 11. Example Target-to-Target Flow Path Illustration). Flow paths may occur via existing perforations, burst or collapsed casing, inadequate cement, or open hole completions.

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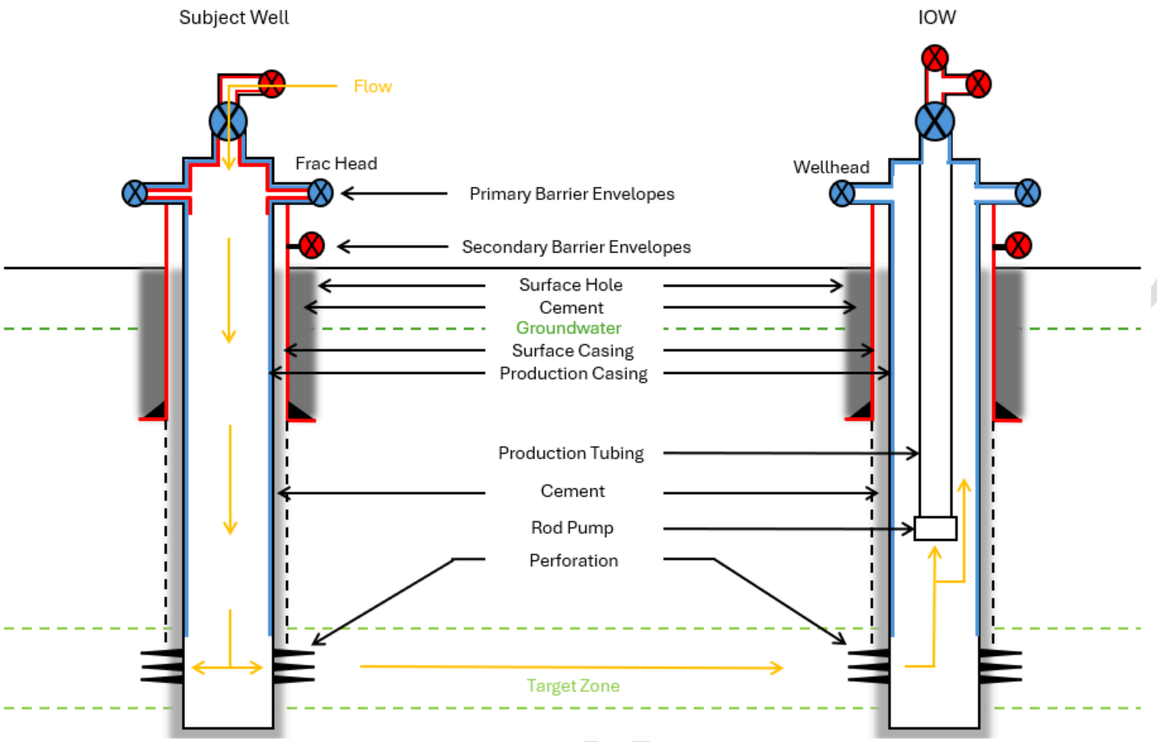
Figure 11. Example Target-to-Target Flow Path Illustration



- Identify barrier envelopes (primary and secondary as required) and illustrate on a schematic (see Appendix F: Sample IOW Barrier Schematic).
- Determine the AMP for each barrier element and identify the lowest AMP within each envelope.
- Assess groundwater protection at the at-risk IOW.

Note: If groundwater protection concerns are identified, scrutinize the at-risk IOW barrier system(s) before fracture stimulation. Consider baseline water well testing in accordance with local jurisdictional requirements.

24.6.3.3 Step 3–Assess IOW Proximity Risk

The closer an at-risk IOW is to a fracture initiation point, the greater the probability of interwellbore communication.

Predicting fracture propagation based solely on spatial distance is unreliable, as no quantitative method exists for precise prediction. See Appendix E: Modeling Fracture Half-Length and Fracture Height, for additional factors affecting probability.

IRP When planning well control (24.6.3 Complete IOW Well Control Plan), the subject well operator should consider both proximity and AMP to minimize risk.

IRP Real-time pressure monitoring (i.e., instantaneous and continuous) with alarms below the IOW's AMP should be considered as a risk mitigation measure.

24.6.3.4 Step 4–Identify IOWs with Active/Pending Downhole Operations

At-risk IOWs with active or pending downhole operations (e.g., drilling and well servicing) may require special planning such as delaying fracture stimulation or modifying fracture parameters. This planning requires consultation and discussion between the subject well operator and the IOW operator (see 24.6.5 Consult with IOW Operators).

IRP The subject well operator shall ensure that operators of at-risk IOWs with active downhole operations are informed of pending fracture stimulation at the subject well (see 24.6.5 Consult with IOW Operators).

24.6.3.5 Step 5–Consider Additional Operational-Specific Hazards

The Hazard Register can be used to cross-reference barrier analysis results against known hazard scenarios. Operators are encouraged to integrate Hazard Register content into existing risk assessment processes.

IRP The subject well operator shall incorporate the IRP 24 Hazard Register, or equivalent known hazard scenarios, into documented risk assessment processes.

24.6.4 Complete IOW Well Control Plan

The IOW risk assessment is the essential first step in identifying at-risk IOWs that require a well control plan. The well control plan is developed in direct response to the findings of the risk assessment and is critical for maintaining well control in all at-risk IOWs.

Special consideration of the condition of abandoned at-risk IOWs and at-risk IOWs with active downhole operations is necessary to ensure that any constraints affecting well control plan options are fully evaluated.

IRP The subject well operator shall inform the appropriate jurisdictional regulator if an at-risk IOW has no legally responsible or financially capable operating company (see 24.6.5 Consult with IOW Operators).

IRP Each at-risk IOW shall have a Well Control Plan that reflects its specific risk assessment.

IRP The subject well operator and the IOW operator shall engage in a collaborative process to develop a mutually agreed-upon Well Control Plan (see 24.6.5 Consult with IOW Operators).

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IRP If there is no IOW operator, the subject well operator should assess risks, implement mitigation strategies, and/or adjust the completion scope in proximity to the IOW. This should be done in consultation with the local jurisdictional regulator.

This section outlines well control practices the subject well operator may consider for at-risk IOWs. The operator consultation section (see 24.6.5 Consult with IOW Operators) addresses the ongoing discussions expected between the subject well operator and the IOW operator to develop an appropriate well control plan.

24.6.4.1 Identify IOW Well Control Practices

An at-risk IOW well control practice is a component of the IOW Well Control Plan. Practices are selected for each at-risk IOW based on the IOW Risk Assessment. They may include, but are not limited to, one or a combination of the following:

- **No Action Required**: If the risk of a well communication event is within the subject well and IOW operator's risk tolerance (e.g., deemed low), the IOW may not require any action or monitoring during the subject well's fracture stimulation operation. Wells classified as minimal-risk will have no action required (see 24.6.3.1 Step 1–Determine At-Risk IOWs).
- **Monitoring**: Observing at-risk IOW parameters (on flow paths in real-time) to trigger well control actions if needed. Monitoring may be conducted remotely (e.g., drones, satellite) or by onsite personnel, as determined by the subject well operator and/or IOW operator. Communication contingencies are in place in the event of a monitoring system failure.
- **Shut-in**: Closing the at-risk IOW flow paths. This practice may be implemented when the risk assessment confirms the adjusted maximum pressure is sufficient to retain well control.
- **Pressure Relieving System**: Installing a piping and fluid storage system to contain fluid released from an at-risk IOW once a pre-determined pressure is reached on a flow path. Consider the following when designing the system:
    - lowest adjusted maximum pressure on the flow path
    - reservoir and/or fracture stimulation fluid type (e.g., gas or liquid, sweet or sour)
    - maximum potential flow rate from the at-risk IOW
    - fluid volume

See IRP 04: Well Testing and Fluid Handling.

- **Installation of Additional Barrier Elements**: Adding an additional barrier element to an existing barrier envelope to improve well integrity. This may be temporary or permanent and may be required during fracture stimulation operations on the subject well. Examples include installing a downhole

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retrievable bridge plug or permanently abandoning with a bridge plug and cement in accordance with regulations.

IRP If none of the above mitigation strategies are possible (e.g., abandoned or orphan well), the subject well operator shall assess and mitigate risk, if necessary, when planning and executing the fracture stimulation (see 24.4 Change Management).

24.6.5 Consult with IOW Operators

Subject well operators are expected to engage with IOW operators and work collaboratively to develop a mutually agreed-upon well control plan for each at-risk IOW (see 24.6.4 Complete IOW Well Control Plan). The complexity of the project reflects the level of consultation needed–more complex projects may require multiple meetings and more time to reach consensus.

> **Note:** For orphan wells, the operator is the local jurisdictional regulator and/or local orphan well association.

IRP The subject well operator shall, at a minimum

- initiate a formal consultation request at least 30 days before the planned fracture stimulation operation:
  - to inform the IOW operator of an IOW that may be at risk from the pending fracture stimulation, and
  - to engage in consultation to collaboratively develop and agree on an IOW Well Control Plan for the fracture stimulation period,

> **Note:** The minimum 30 days is a guideline intended to provide suitable lead time for the initial communication to reach the appropriate individual at the IOW operator and allow time for the IOW operator to reply.

- re-initiate a documented request if no response is received within a reasonable period (minimum 15 days),
- provide the IOW operator a minimum data about the planned fracture stimulation, including the following:
  - subject well license, IOW license, and Unique Well Identifier (UWI),
  - target geological formation and/or planned TVD, subsea, fracture half-length (x_f), and fracture height (z_f),
  - map of the FPZ (see 24.6.2.3 Identify IOWs Within the Fracture Planning Zone),
  - closest distance from the subject well to the IOW,

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  - expected date of the fracture stimulation,

- establish field-level communication contacts between the subject well and IOW operators for pre-, during, and post-fracture stimulation notifications,
- engage in collaborative consultation to develop a mutually agreed-upon IOW Well Control Plan (including emergency protocols) and
- finalize and document the confirmed IOW Well Control Plan and ensure appropriate field-level notifications.

IRP The subject well operator should maintain records of communications with the IOW operator regarding the consultation process, including risk assessment and confirmation of the final IOW Well Control Plan.

IRP The subject well operator should provide a public contact point (e.g., fracnotifications@producer.com) on the company website to facilitate third-party communications.

IRP The IOW operator shall, at a minimum

- develop an internal process to review and respond to subject well operator requests,
- establish and publicize a moderated corporate notification process (e.g., phone number and/or email),
- assign a competent individual with knowledge of the IOW(s) in question,
- acknowledge receipt of a consultation request within 15 days,
- provide all publicly available wellbore data (e.g., survey, tubulars, cement tops, stimulations),
- disclose any planned operations at the offset well that may be influenced by the proposed fracture stimulation,
- engage in collaborative consultation with the goal of developing a mutually agreed-upon IOW Well Control Plan. Mitigation may include requesting installation of surface pressure recorders at the subject well operator’s expense,
- finalize and document the confirmed IOW Well Control Plan and ensure appropriate field-level notifications,
- notify the subject well operator’s field contact if an unexpected pressure communication approaches the IOW’s AMP and
- follow the agreed-upon IOW well control plan.

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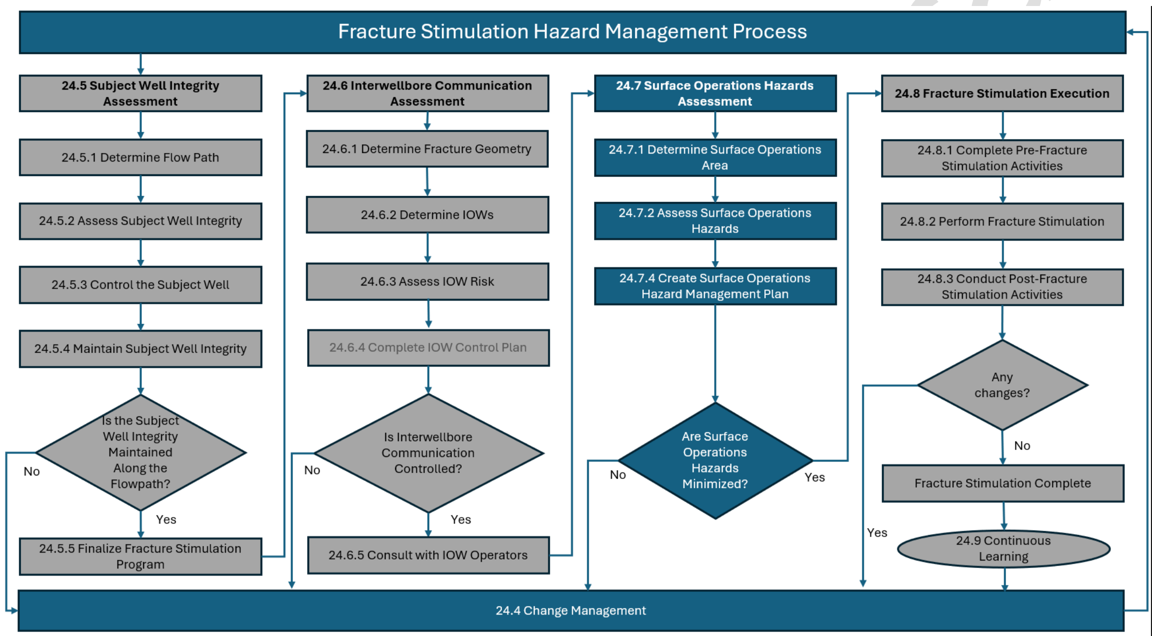
24.7 Surface Operations Hazards Assessment

The next stage of the FSHMP is the Surface Operations Hazard Assessment (see Figure 12).

Figure 12. Surface Operations Hazard Assessment in the FSHMP



This stage involves

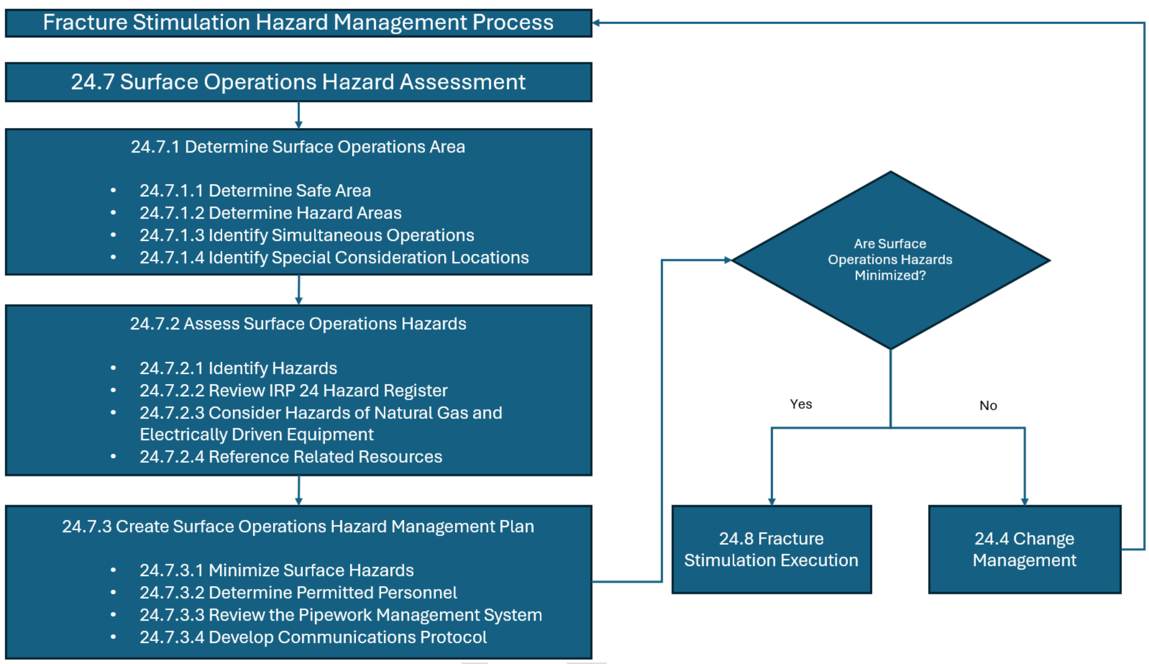
- determining safe and hazard areas,
- identifying simultaneous operations and
- recognizing special consideration locations.

Following this, hazards in the area are assessed by reviewing the IRP 24 Hazard Register and considering risks associated with specific equipment (e.g., natural gas or electrically driven machinery). A Surface Operations Hazard Management Plan is then developed to mitigate risks. This plan includes

- reviewing the pipework management system,
- determining permitted personnel and
- establishing a communication protocol.

If hazards are reduced to an acceptable level in consultation with the Subject Well Operator and service company or companies hazard management practices, fracture stimulation can proceed. If not, the changes need to be managed (see 24.4 Change Management).

Figure 13. Surface Operations Hazard Assessment



The surface operations hazard assessment includes all above-ground equipment and activities except the wellhead equipment (see 24.5 Subject Well Integrity Assessment). This stage identifies surface areas, assesses hazards, and addresses hazard management planning and wellsite execution.

Fracture stimulation is a complex operation. Multi-well leases may increase activity and congestion, often when pumping erosive fluids under high-pressure conditions. Thorough planning before operations begin can help control both identified and industry-known hazards (IRP 24 Hazard Register). The subject well operator is responsible for reviewing surface operations during planning to minimize the likelihood of surface hazards.

IRP **The subject well operator, in consultation with the service company or companies, shall minimize surface hazards to workers, the public and the environment during fracture stimulation operations at the subject well.**

IRP **If an incident occurs at the wellsite during fracture stimulation operations, the subject well operator's Emergency Response Plan (ERP) must be reviewed and local jurisdictional regulations may require notification.**

Common options to minimize surface hazards include, but are not limited to, the following:

1. Conducting a Surface Operations Hazard Management Plan using the IRP 24 Surface Hazard Management Assessment
(see Figure 12).
2. Adjusting the Fracture Stimulation Program.
3. Modifying the timing to minimize simultaneous operations.

24.7.1 Determine Surface Operations Area

The surface operations area is the area from the subject well to the lease boundary where surface hazards are identified and managed.

To control hazards within this area, the following is identified, clearly marked, and communicated to all field workers:

- Safe areas
- Hazard areas (e.g., active operations areas, exclusion zones, elevated hazard zones, silica exposure areas)
- Simultaneous operations areas

Beyond the lease boundaries, special consideration locations may also require a surface hazard assessment.

IRP The subject well operator, in consultation with the service company or companies, shall conduct a surface hazard assessment to determine relevant safe areas, hazard areas, simultaneous operations areas, and special consideration locations for the fracture stimulation operation.

IRP The subject well operator should post a site map that clearly identifies these areas and their proximity to the fracture stimulation operations. The operator should also ensure that the risk level associated with each area is clearly communicated to field workers. See Figure 14. Lease Map Showing Safe Area and Hazard Areas, for an example.

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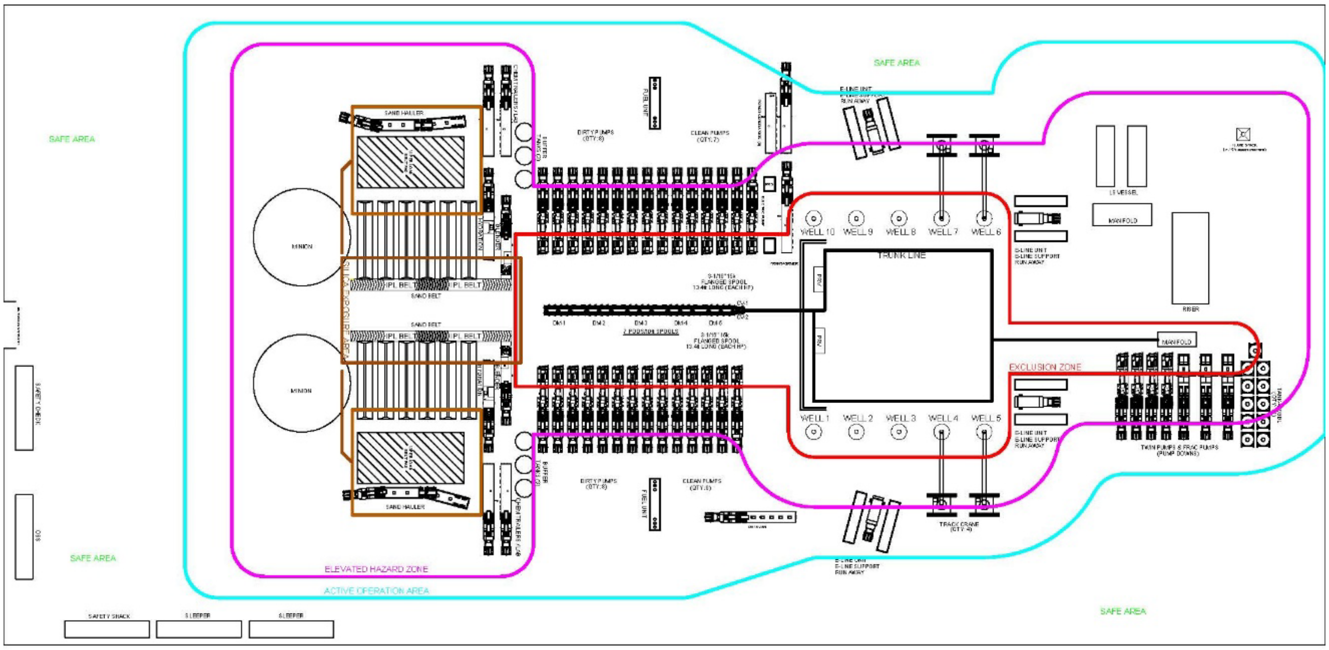
Figure 14. Lease Map Showing Safe Area and Hazard Areas



24.7.1.1 Determine Safe Area

The safe area is a designated area with minimal hazards, where workers can enter without special authorization. It may be used for mustering, egress, first aid, safety meetings, and job preparations.

IRP The subject well operator, in consultation with the service company or companies, shall determine the safe area location before operations begin.

24.7.1.1.1 Identify Active Operations Area

The active operations area is the portion of the lease where fracturing operations occur (see Figure 12). It includes the exclusion zone, elevated hazard zone, and silica exposure area. Access may be limited to essential personnel only with the proper protective and monitoring equipment in accordance with company and regulatory requirements.

IRP The subject well operator, in consultation with the service company or companies, shall determine the active operations area and during pre-job planning (complete well on paper process) before operations begin and services are dispatched.

IRP The boundaries of designated areas and zones may change during operations. Any changes must be communicated to personnel (see 24.4 Change Management).

24.7.1.1.2 Determine Exclusion Zone

An exclusion zone is a predefined area with potential for high-risk hazards where access is restricted to authorized personnel only. It is established around high-pressure equipment and other high-risk areas on the lease.

The location and boundary of the exclusion zone is determined by the subject well operator in consultation with the service company or companies. The objective is to limit exposure and control access to these areas.

> **Note:** Exclusion zones may already be defined in company SOPs and technical procedures.

IRP Exclusion zones shall be

- clearly marked with a visual barrier (e.g., red caution tape, pylons, signage) and communicated to all on-site personnel,
- determined through a site-specific hazard assessment and
- established to the largest practicable perimeter allowed by the lease size and spacing.
- Discussed at daily safety meetings

IRP Any boundary changes during operations shall follow a management of change (MOC) process before proceeding.

IRP Exclusion zones may change as operations progress and must be continually re-assessed in accordance with regulations.

IRP Entry into an exclusion zone shall be avoided. When entry is necessary, the subject well operator and service company or companies shall

- have a formal approval process in place,
- minimize the number of workers entering the zone and the length of time they remain in the zone and
- ensure the approval process complies with site requirements, operator procedures, and applicable jurisdictional regulations.

24.7.1.1.3 Identify Elevated Hazard Zones

As surface operations progress within the active operations area, certain fracture support activities present elevated hazards. Examples include silica exposure, wireline

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operations, fracture fluid transfer, low pressure equipment, and fuelling while pumping (see Figure 12).

IRP The subject well operator, in consultation with the service company or companies, shall identify elevated hazard zones and re-assess them as the fracture operation progresses.

The subject well operator and service company or companies are responsible for discussing elevated hazard zones at safety meetings to alert permitted personnel (see 24.8 Fracture Stimulation Execution). A visual barrier may be used to distinguish elevated hazard zones within the active operations area.

24.7.1.1.4 Identify Silica Exposure Area

The silica exposure area is where there is an elevated probability of silica dust exposure. The boundaries of this area may change based on factors such as weather conditions, equipment in use (e.g., air can, sand conveyor), and whether operations are active or inactive.

IRP The subject well operator and service company or companies shall establish a combination of control measures to follow best practices and limit silica exposure during operations.

24.7.1.2 Identify Simultaneous Operations

Simultaneous operations are any other operation occurring on the same wellsite that are not directly part of the fracture stimulation but take place during its execution. These operations increase the likelihood of surface incidents and can elevate risk at all stages of the fracture stimulation (pre, during, post-operations). For effective hazard management planning, the location and proximity of simultaneous operations to the subject well is identified.

Examples of simultaneous operations include, but not be limited to the following:

- Flowback (see Figure 15. Simultaneous Operations Showing Safe Areas and Hazard Areas)
- Wireline operations on an adjacent wellbore
- Drilling while fracturing (see 24.6.3.4 Step 4 Identify IOWs with Active/Pending Downhole Operations)
- Other completions operations (e.g., coiled tubing)
- Transportation activities (e.g., sand, chemical, water, fuel delivery)
- Facility installation
- Existing operating wells and facilities

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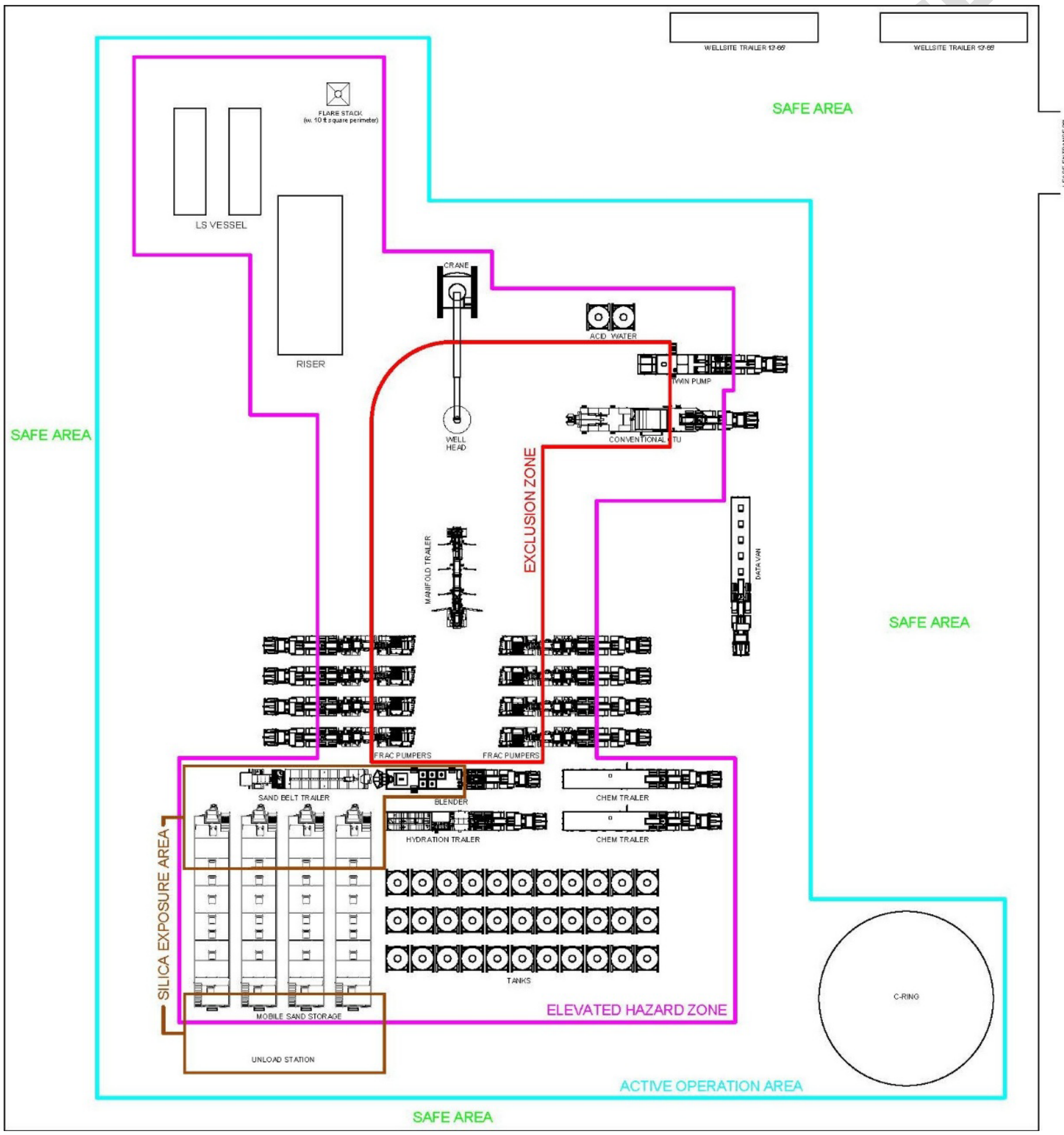
IRP **The subject well operator, in consultation with the service company or companies, shall determine the location of simultaneous operations within the active operation and hazard areas for the full duration of the fracture stimulation. Jurisdictional requirements for posting simultaneous operations control documents shall be followed.**

Figure 15. Simultaneous Operations Showing Safe Areas and Hazard Areas



24.7.1.3 Identify Special Consideration Locations

Fracture stimulation operations may involve off-site activities such as transport, maintenance, or equipment and material storage. Off-lease locations that could be affected during any stage of the fracture stimulation operation require special consideration.

Examples of off-lease surface risks include, but not be limited to the following:

- Extensions of fracture stimulation operations off-lease (e.g., overland pumping operations)
- Proximity to public areas and residential locations
- Road usage impacts
- Offset wells identified in the IOW Risk Assessment
- Known environmentally sensitive areas and wildlife habitats
- Existing infrastructure (e.g., power lines, pipelines)

IRP The subject well operator in consultation with the service company or companies, shall determine and document the location of special consideration areas prior to operations.

24.7.2 Assess Surface Operations Hazards

The surface operations hazard assessment defines boundaries for the safe area, active operations area, elevated hazard zones, exclusion zones, and special consideration locations (see Figure 18). This assessment forms the basis for developing the Surface Operations Hazard Management Plan (see 24.7.3 Create Surface Operations Hazard Management Plan).

IRP The subject well operator, in consultation with the service company or companies, shall identify hazards within the following pre-determined areas:

- Safe area(s)
- Active operations area(s)
- Elevated hazard zone(s)
- Exclusion zone(s)
- Special consideration locations.

IRP The surface operations hazard assessment should be conducted in the following stages:

1. Hazard identification
2. Cross-reference with the IRP 24 Hazard Register
3. Cross-reference with related IRPs

24.7.2.1 Identify Hazards

In addition to the IRP 24 Hazard Register, several topics specific to fracture stimulation operations require explicit attention including identifying and assessing relevant hazards in the following areas:

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- **Safe area(s):** Hazards in safe areas can be overlooked. In the event of a surface incident, the safe area needs to allow easy entry and exit on foot or by vehicle. Pay special attention to uneven or slippery ground and obstacles that block access or egress.
- **Hazard areas**: includes the exclusion zone, active operations area, and elevated hazard zones. Given the nature of fracture stimulation treatments and working conditions, surface equipment, support services, the pipe body, and connections are under stress creating potential hazards such as
    - erosion,
    - over-pressuring,
    - chemical incompatibility and/or degradation and
    - stress fatigue.

  Note: Mitigation and control options for these hazards are in the IRP 24 Hazard Register. Subject well operators, in consultation with the service company or companies, review these hazards and account for the specific conditions of the site's fracture stimulation program when developing controls.

- **Simultaneous operations**: The severity and proximity of another surface incident during operations can increase the risk to the active operation area. Surface hazards from simultaneous operations may include
    - an unexpected kick while drilling,
    - wireline operations in progress on an adjacent well or
    - an uncontrolled flowback of wellbore fluids at an adjacent well.

  Note: Interwellbore communication at an offset well may cause surface hazards. Onsite downhole simultaneous operations can also impact the subject well. See 24.6.3 Assess IOW Risk. These onsite offset wells are considered IOWs and are included in the IOW Risk Assessment.

- **Special consideration locations**: Assess hazards for each special consideration location. Potential hazard scenarios are listed in the IRP 24 Hazard Register. Subject well operators and the service company or companies are encouraged to pay particular attention to
    - any extension of fracture stimulation operations off-lease (e.g., overland pumping operations),
    - proximity to public and residential locations,
    - road usage,
    - offset wells included in the IOW Risk Assessment,

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- known environmentally sensitive areas and wildlife and
- other existing infrastructure (e.g., power lines, pipelines).

24.7.2.2 Review IRP 24 Hazard Register

The IRP 24 Hazard Register lists industry-recognized surface hazards, some of which may be unfamiliar to subject well operators. It enables subject well operators to proactively identify potential hazards before an incident occurs. Subject well operators are encouraged to cross-reference hazards identified in surface areas with the IRP 24 Hazard Register.

IRP The subject well operator, in consultation with the service company or companies, shall use the IRP 24 Hazard Register to assess hazards in designated safe areas, hazard areas, simultaneous operations, and special consideration locations.

24.7.2.3 Consider Hazards of Natural Gas and Electrically Driven Equipment

Note: See Energy Workforce and Technology Council, Well Stimulation Industry Guidelines March 2023, for more information.

IRP The subject well operator, in consultation with the service company or companies, shall review hazards associated with natural gas and electrically driven equipment, including power generation and storage.

IRP The service company(ies) shall have operational procedures and controls in place for the safe operation of such equipment.

24.7.2.3.1 Natural Gas-Fueled Equipment

Hydraulic fracturing worksites may use various types of natural gas-fueled equipment (i.e., devices generating mechanical or electrical power). Each has specific fuel supply requirements and uses gas differently to produce either mechanical or electrical power.

1. Dual-fuel diesel engines–commonly used for mechanical power, directly coupled to a fracture pump.
2. Gas turbines–operate exclusively on natural gas; may be coupled to a generator or directly to a hydraulic fracturing pump.
3. Natural gas engines–spark-ignited engines that use natural gas as a single fuel source.

Sources of Natural Gas

Natural gas used in the field often comes from three sources:

1. field gas
2. compressed natural gas (CNG)

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3. liquified natural gas (LNG)

Each source requires a dedicated equipment package onsite. A safe gas distribution system is required to safely transport the gas from the source to each individual fracture engine, turbine, or generator engine.

Gas Quality

Gas quality parameters (e.g., pressure, temperature), vary by equipment type and needs to be understood by distributors, service companies and supply companies.

IRP Any liquids are detrimental to equipment operation. Liquids (e.g., water and/or hydrocarbons) shall be removed. Adequate detection methods shall be in place, and gas supply shall be isolated if either is detected.

IRP The gas must have zero H_2S concentration to meet gas quality parameters.

IRP A gas sample analysis shall be conducted to confirm gas quality.

Process and Distribution Equipment

IRP All natural gas handling and processing equipment shall be suitable for natural gas service, designed for the application, and compliant with applicable national, local and industry codes and regulations.

IRP Equipment design shall consider pressure/temperature ratings, sizing, class ratings, and the type and quantity of risk mitigation for component failures.

IRP The natural gas equipment shall have adequate filtration to prevent ingress of foreign objects, water, and excess oil.

IRP Supply equipment shall have a means to manually isolate the primary gas supply source and delivery lines, plus automatically activated isolation devices for safety-critical events (e.g., ESD valve).

IRP A site schematic showing gas line location, release point, and equipment layout should be available.

IRP Methods and locations for emptying or depressurizing natural gas lines should consider worker proximity and unclassified equipment/electronics.

IRP All components should be appropriately labeled.

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Emergency Preparedness

IRP The ERP shall address responses to natural gas-related emergencies (e.g., major gas release, thermal event) and actions required on natural gas equipment during non-gas-related emergencies.

24.7.2.3.2 Electrical Equipment

IRP Electrical equipment shall be certified by an agency accredited by the Standards Council of Canada.

IRP Electrical equipment must be suitable for its location and selected for the environmental and operational conditions it may be exposed to.

IRP Flammables must not be stored near electrical equipment or ignition sources. See Energy Safety Canada's Fire and Explosion Hazard Management Guideline.

IRP Adequate ventilation shall be provided to prevent excessive ambient temperatures.

IRP The service company shall use CSA B149.1 Natural Gas and Propane Installation Code to determine clearance distances between arc-producing equipment and combustible gas relief devices or vents.

IRP All electrical equipment shall be properly grounded and bonded in compliance with the CSA National Electrical Code to maintain equal potential and dissipate static electricity.

IRP The exclusion zone for high-voltage equipment shall be defined jointly by the subject well operator and service company.

IRP Only qualified personnel shall work on equipment or enter the exclusion zone. See 24.7.1.1.2 Determine Exclusion Zone.

24.7.2.4 Reference Related Resources

A review of relevant IRPs and guidelines may provide additional guidance. Examples may include the following:

- IRP 04: Well Testing and Fluid Handling
- IRP 05: Minimum Wellhead Requirements
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 08: Pumping of Flammable Fluids
- IRP 13: Wireline Operations

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- IRP 20: Wellsite Design Spacing Recommendations
- IRP 21: Coiled Tubing Operations
- IRP 29 Temporary Pipework, Securement, and Restraint

24.7.3 Create Surface Operations Hazard Management Plan

Surface operations hazard management planning establishes control measures for hazards identified in the safe area, hazard areas, simultaneous operations areas, and special consideration locations with attention to both hazard severity and proximity to the fracture operation.

IRP The subject well operator, in consultation with the service company or companies must conduct surface operations hazard management planning that includes control measures for hazards identified in surface operations areas (safety area, hazard areas, simultaneous operations areas, and special consideration locations).

24.7.3.1 Minimize Surface Hazards

Once hazard management planning is complete, the subject well operator reviews the plan to determine whether surface operation risks have been minimized. The review considers whether the combination of controls and mitigations for hazards in the defined surface areas provides confidence that risks are within the operator’s risk tolerance.

If confidence is lacking, the plan is revisited. This may involve the following:

- Reassessing surface operations areas (24.7.1 Determine Surface Operations Area)
- Reassessing hazards (24.7 Surface Operations Hazard Assessment)
- Adjusting the timing of simultaneous operations
- Modifying the fracture stimulation program

Only once the subject well operator is confident that surface operation risks have been adequately controlled and mitigated may the fracture stimulation be executed.

24.7.3.2 Determine Permitted Personnel

Restricting access to certain areas is a key control measure for mitigating hazards during a fracture operation. Each surface area is reviewed throughout the operation to determine if changes to personnel restrictions are required as conditions evolve.

The exclusion zone contains the highest risk on site. The subject well operator and service company or companies work together to limit exposure and access to the high-pressure area to the greatest extent possible.

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IRP The subject well operator, in consultation with the service company or companies shall conduct hazard management planning to determine permitted personnel, duration of exposure, permitted tasks, and tools for the following:

- Safety areas
- Hazard areas
- Simultaneous operations areas
- Special consideration locations

24.7.3.3 Review Pipework Management System

The Pipework Management System, also referred to as an Iron Management System, is a key control to reduce the risk of failure of temporary pipework used during fracture stimulation operations.

IRP The Subject Well Operator, in consultation with the Service Company or Companies, shall verify that a pipework management system is in place.

IRP The pipework management system shall address, at a minimum:

- Suitability of equipment for expected pressures and fluids,
- Inspection and maintenance practices, and
- Verification that equipment is fit for service prior to use.

IRP Temporary pipework, including flexible hoses, connections, restraints, anchoring, installation, and inspection, shall meet the requirements of IRP 29: Temporary Pipework.

Note: IRP 29 provide detailed requirements for pipework management systems, including tracking, certification, inspection, and installation practices.

24.7.3.4 Develop Communications Protocol

Simultaneous and supporting operations near the subject well increase the probability of surface hazards. Regular, effective communication among all parties is essential. A communication protocol may include onsite operations staff and third-party suppliers who are on site for extended periods (e.g., fire suppression, fuel, chemical and medical personnel).

IRP The subject well operator, in consultation with the service company or companies active in surface operations areas, shall establish a communication protocol.

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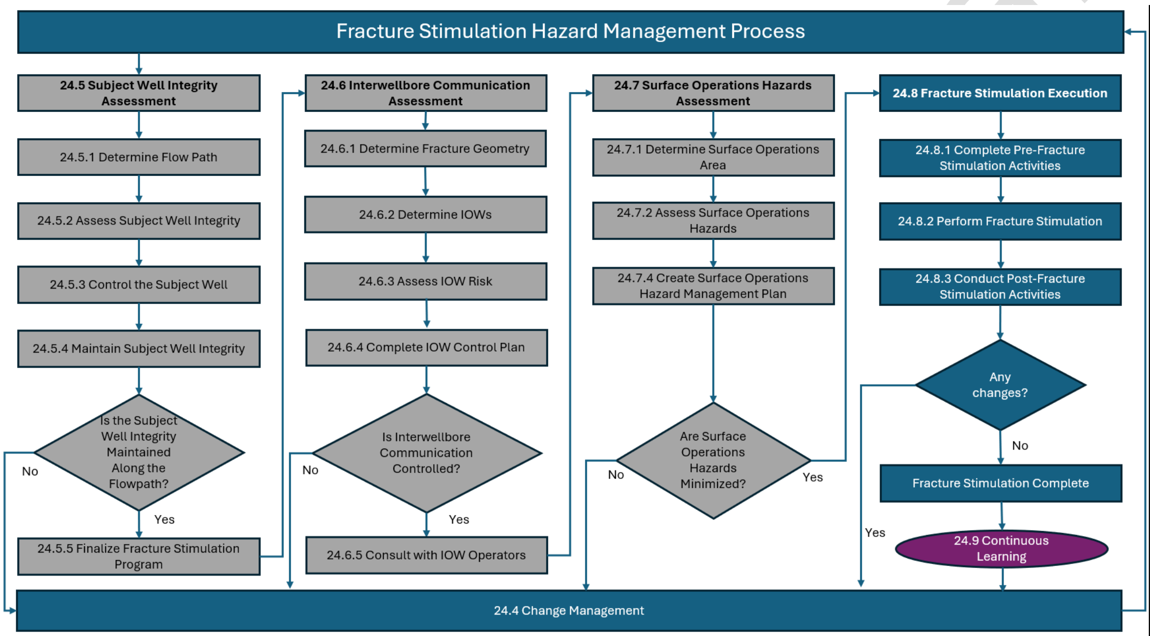
24.8 Fracture Stimulation Execution

The key aspects of executing fracture stimulation are shown in Figure 16.

Figure 16. Fracture Stimulation Execution in the FFSHMP

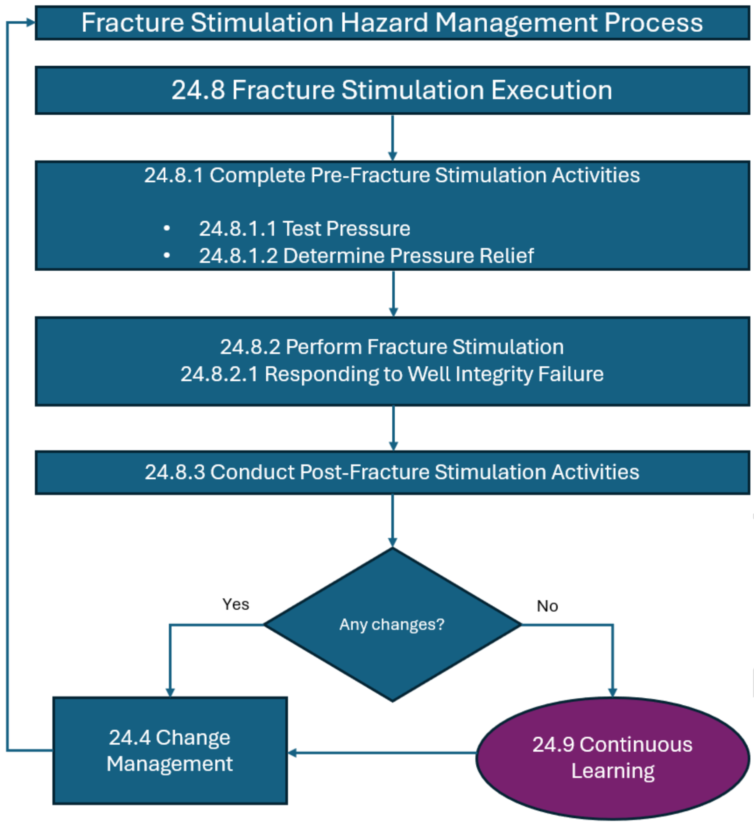


Fracture stimulation execution includes the following:

- Pre-stimulation activities such as pressure testing and verifying pressure relief to ensure system integrity
- Fracture stimulation once integrity is verified
- Post-stimulation activities such as evacuating fluid from the lines

Any changes during the process are managed in accordance with 24.4 Change Management. Upon completion, a review is conducted to identify opportunities for improvement and support continuous learning (see Figure 17).

Figure 17. Fracture Stimulation Execution



Once the fracture stimulation operation is underway, effective communication is essential. Particular attention is required for the high-pressure area, as the conditions and risk level in this area can change as the operation progresses. The subject well operator and service company or companies communicate to ensure it is clear when the high-pressure area is active.

IRP **The subject well operator / wellsite supervisor, in consultation with the service company or companies shall communicate the following for each determined surface operations area (see 24.7.1 Determine Surface Operations Area):**

- Hazards and control measures
- Elevated hazard zones within any surface operations areas
- Permitted access personnel
- Duration of exposure
- Permitted tasks and tools

Surface hazard management planning may be organized chronologically into pre-fracture, during-fracture, and post-fracture stimulation phases.

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IRP The subject well operator must confirm casing integrity before, during, and after fracture stimulation in accordance with local jurisdictional regulations.

IRP The subject well operator should ensure the Adjusted Maximum Pressure (AMP) is not exceeded before, during, or after fracture stimulation operations.

24.8.1 Complete Pre-Fracture Stimulation Activities

Pre-fracture stimulation refers to all on-lease fracture stimulation activities that occur before pressurizing the high-pressure iron. Fracture stimulation operations may involve simultaneous events that need to be communicated to personnel before operations begin.

Some pre-fracture stimulation surface hazards may not be obvious to onsite personnel– for example, silica dust during sand transfers to onsite storage. All personnel are responsible for maintaining awareness of surface hazards.

IRP Before pressurizing the high-pressure iron, the service company or companies and subject well operator shall ensure personnel are aware of the following:

- Additional obstacles on the ground, such as treating iron, can be tripping hazards.
- Treating iron is rigged in to allow for normal movement (jacking) while minimizing wear points during pumping operations.
- Treating iron is restrained in accordance with local jurisdictional requirements (see 24.7.3.3 Review Pipework Management System).
- Continuous proppant and product transport can result in high volume traffic, creating poor sight lines for both pedestrians and drivers.
- Hazardous chemicals and materials (e.g., silica dust, hydrochloric acid, hydrocarbons, and other stimulation chemicals) are present and exposure controls plans are in place.

IRP Prior to initiation of fracturing operations, the subject wellsite supervisor shall ensure that subject well controls have been executed (see 24.5.3 Control the Subject Well).

IRP Prior to initiating fracturing operations, the subject wellsite supervisor should verify that the IOW operator has executed the mutually agreed well control plan (see 24.6.4 Complete IOW Control Plan).

The subject well operator may collect IOW pressure data before the fracture stimulation operation to establish baseline data.

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IRP The subject wellsite supervisor shall conduct the following:

- Review and confirm the accuracy of data and information supplied in the IOW Well Control Plan.
- Ensure contingencies are in place in the event of an IOW monitoring communication failure.
- Conduct an overview of the physical FPZ area (i.e., on and offsite) to identify any other planned operations during fracture stimulation.
- Communicate effectively with the IOW active downhole operations wellsite supervisor prior to subject well fracture stimulation.
- Ensure monitoring described in the IOW Well Control Plan is fully operational.
- Ensure all IOW field notifications have been completed (see 24.6.5 Consult with IOW Operators).
- Oversee the implementation of the IOW Well Control Plan, as mutually agreed between the subject well operator and the IOW operator.

24.8.1.1 Test Pressure

Pressure testing is required by regulation to confirm that system integrity is adequate to proceed with operations.

IRP Before pressure testing, the maximum test pressure shall be established, communicated, and not exceed the maximum allowable operating pressure of the lowest-rated component (lowest working pressure).

IRP A pre-job safety meeting must be held and documented, and a hazard assessment performed, verified, and communicated before pressure testing.

IRP At a minimum, the system should hold the test pressure for as long as necessary to detect leaks and allow the pressure to stabilize. Test duration may vary based on local jurisdictional requirements or those of the owner and/or prime contractor, or service company.

IRP If temporary piping is disassembled and reassembled during an operation or between stages, the affected components shall be pressure tested.

Pressure testing is required to confirm that system integrity is adequate prior to initiating fracture stimulation operations.

IRP The subject well operator, in consultation with the service company or companies, must ensure that all treating iron and associated equipment are pressure tested in accordance with applicable local jurisdictional regulatory requirements.

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Note: See IRP 29 for further information regarding pressure testing.

IRP **All fuel supply components (including supply, consumption, and associated control systems) shall be pressure tested before field pressure operations.**

IRP Associated fluid-containing equipment and piping (e.g., chemical injection, hydraulics, and steam) should be function and leak tested prior to operation.

IRP **Pressure testing shall be completed prior to initial operations and following any disassembly and reassembly of temporary piping that may affect system integrity.**

24.8.1.2 Determine Pressure Relief - Hydraulic Fracturing Example

The pressure relief strategy for the hydraulic fracturing example in Table 3 is based on the following principles:

- The treatment pressure range determines the overall strategy for the pressure relief system.
- Secondary protection for pump kickouts/shutdowns is identified. Pump kickouts form part of the pressure relief hierarchy, with the primary purpose of shutting down operations before activation of the pressure relief device.

The Maximum Anticipated Treating Pressure helps determine the offset pressure for the primary pressure relief device. Different types of pressure relief devices have specific activation tolerances, which need to be considered during selection.

Table 3. Pressure Relief – Hydraulic Fracturing Example

kPa	Settings	Action
69,000	Maximum Allowable Operating Pressure	Tolerance Range for Pressure Relief Activation
60,000	Pump Trip 2	
58,000	Pump Trip 1	
53,500		Treatment Pressure Range
51,300		

24.8.2 Perform Fracture Stimulation

IRP **The subject well operator must maintain a copy of the IOW Well Control Plan at the subject wellsite in accordance with local jurisdictional regulations.**

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IRP The subject wellsite supervisor shall

- communicate effectively with the IOW active operations wellsite supervisor during fracture stimulation operations,
- initiate notification in accordance with local jurisdictional regulations if an uncontrolled well event occurs, subject well integrity fails, or communication to an IOW occurs, and
- take appropriate actions on the subject well to reduce hazards when approaching the subject well's or an IOW's adjusted maximum pressure (AMP) (i.e., go to flush, stop pumping, relieve pressure).

IRP Once the fracture stimulation is underway, the service company or companies and subject well operator must ensure personnel are aware of any change in hazards and related controls. These may include the following:

- Communicating the location of the safe areas and the controls in place to restrict access.
- Following a communications protocol for coordination with all service company's onsite personnel, including those involved in simultaneous operations, and any IOW communication plans (see 24.6.5 Consult with IOW Operators).
- Assigning personnel to continuously monitor the treating iron and subject well surface equipment:
    - Ensure the treating iron can move freely (jacking) while avoiding wear points; bound iron may cause stress cracking.
    - Watch for leaks, as small leaks can quickly escalate.
    - Ensure pressures do not exceed the AMP of the wellhead or the OEM pressure rating of the surface equipment and comply with local jurisdictional requirements.
    - Ensure rates do not to exceed OEM-recommended maximum linear velocity.

IRP The lines between the fracture pump and wellhead shall be pressure tested above maximum allowable operating pressure, without exceeding the OEM-rated working pressure of the equipment. Refer to local jurisdictional regulations for specific requirements.

IRP The subject well operator, in consultation with the service company or companies, should have a communication protocol to verify equipment operation and valve positions (opened or closed) along the fracturing fluid flow path. This protocol should include, but is not limited to, the wellsite supervisor, the fracture supervisor, and all other service companies.

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Note: This is sometimes referred to as three-way communication or triple handshake method.

24.8.2.1 Responding to Well Integrity Failure

IRP When subject well or offset well integrity cannot be maintained, corrective actions must be implemented.

- Fracture stimulation operations shall cease immediately.
- If well control cannot be maintained the ERP must be activated.
- Once well control is restored/maintained, the failure location and probable cause must be determined. Appropriate corrective actions shall be taken to restore well integrity.
- The subject well operator shall conduct a risk evaluation to determine if the stimulation can safely resume based on corrective actions taken. See 24.4 Change Management.

24.8.3 Conduct Post-Fracture Stimulation Activities

Post-fracture stimulation refers to all operations that occur after the treatment iron has been depressurized. These operations present many of the same surface risks as pre-fracture stimulation, with the added concern of flowback risks (see IRP 24 Hazard Register).

Post-fracture stimulation activities include the following:

- Evacuating fluid from all lines
- Issuing simultaneous operation notifications (e.g., pad drilling, perforating, adjacent wellbores)
- Notifying at-risk IOW operators

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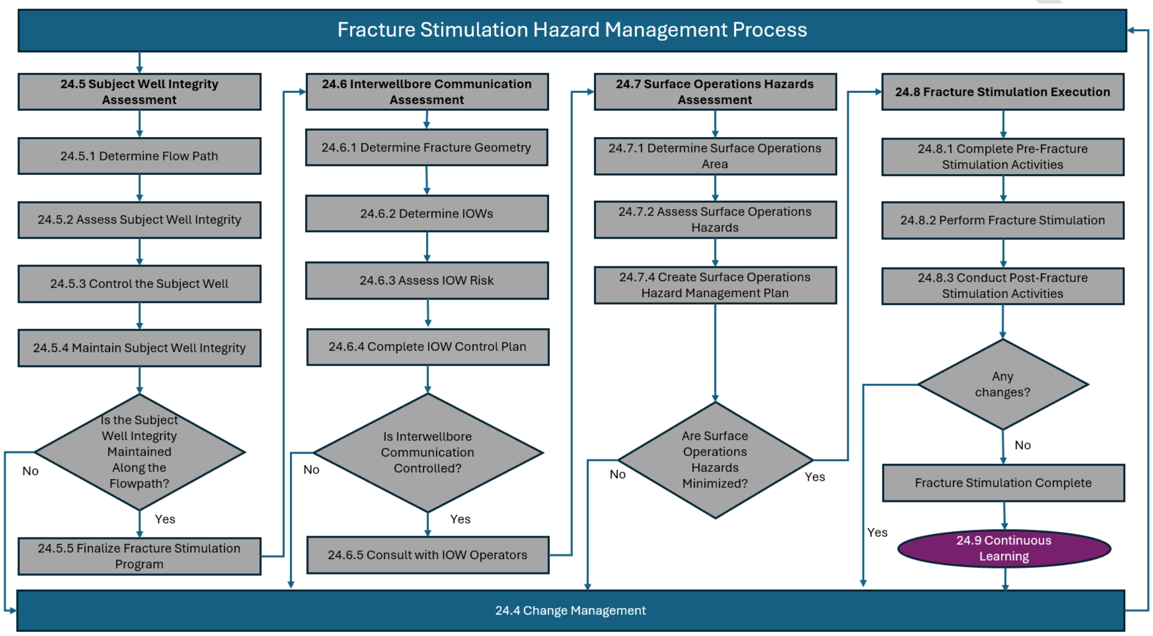
24.9 Continuous Learning

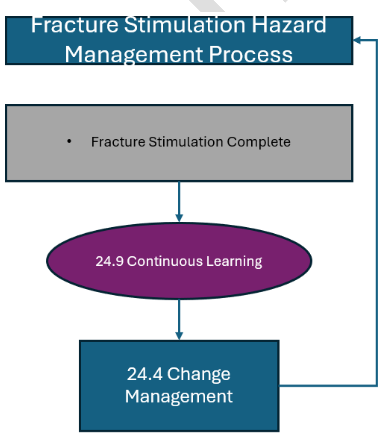
Continuous learning is the final stage of the Fracture Stimulation Hazard Management Process (FSHMP).

Figure 18. Continuous Learning in the FFSHMP



It provides an opportunity to review, evaluate, and document operational outcomes to improve future fracture stimulation practices.

Figure 19. Continuous Learning



Post-operation reviews incorporate structured continuous learning activities with input from all relevant stakeholders—operators, service companies, and field personnel. These reviews record what occurred and help refine planning assumptions, risk management strategies, and execution methods.

IRP Subject well operators shall include continuous learning activities as part of post-operation reviews for all fracture stimulation operations.

Key elements to evaluate include the following:

- **Unexpected Events:** Record all unplanned incidents, near misses, or deviations (e.g., Subject Well Integrity, Interwellbore Communication, Surface Operations). Assess how these were managed, whether they could have been anticipated, and how to prevent or better control them in the future.
- **Change Management:** Document any changes during the operation. Note if they were proactive (based on hazard assessments) or reactive (in response to emerging conditions) and whether they effectively mitigated risk or introduced new issues.
- **Model Updates:** Update fracture models with new data, using unexpected results to calibrate expectations and improve predictive accuracy for future programs.

A well-documented post-operation review builds institutional knowledge, enhances safety performance, and embeds continuous improvement into fracture stimulation programs.

Sharing learnings–through committees, associations, IRP 24 Hazard Register updates, and regulatory bodies–supports broader industry improvement.

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Appendix A: Revision Log

The revisions to IRP 24 are logged in the following table. Refer to 24.0.7 Background for additional information about the history of this IRP.

Edition 2

The purpose of the review for edition 2 of IRP 24 was to complete a full scope review of the IRP and hazard register to match current industry practices and technology as per the terms of reference.

Table 4. Edition 2 Revisions

Section	Remarks and Changes
General	Updated to current IRP template: • Disclaimer • Range Update Enform to Energy Safety Canada • Range of obligation terminology • Revision log/acknowledgments • Moved definitions and acronyms to an Appendix for Glossary (Appendix C) • Terminology and style updates to match current IRPs and DACC Style guide
24.3 Fracture Stimulation Hazard Management Process	Updated the process and associated flowcharts.
24.3.2.4 Monitoring and Reporting Induced Seismicity	Updated to reflect current industry best practices.
24.4 Change Management	Expanded previous change management section into new chapter.
24.5.2.1 Analyze Subject Well Barrier Envelope	• Added recommendation to consider tri-axial load modelling for initial casing design and when well design assumptions change.
24.6.1 Determine Fracture Geometry	• Replaced Fracture Planning Zone Determination with Determine Fracture Geometry. • Expanded to incorporate fracture height (z_f).
24.7 Surface Operations Hazard Assessment	• Added exclusion zone terminology for high hazard areas to align with IRP 4 and 29. • Included silica exposure areas and simultaneous operations areas (removed reference to concurrent operations).
26.6.3 Assess IOW Risk	Updated five-step process to include consideration of fracture height.

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Section	Remarks and Changes
24.7.2.3 Consider Hazards of Natural Gas and Electrically-Driven Equipment	Added natural gas and electrically-driven equipment hazards to consider when assessing surface operations hazards.
24.7.3.3 Review Pipework Management System	Replaced iron management with review pipework management system to align with IRP 29.
24.8 Facture Stimulation Execution	Expanded previous fracture stimulation section into its own chapter.
24.9 Continuous Learning	Expanded previous continuous learning section into its own chapter.
Appendix B: Case Studies	Added case studies to give examples of how IOWs are determined and reassessed when needed.
Appendix D: Casing Burst and Collapse Considerations	Added tri-axial load model examples.
Appendix E: Modeling Fracture Half-Length and Fracture Data Sources for x_f and z_f Modeling	Updated to incorporate fracture height.

The following individuals helped develop this edition of IRP 24 through a subcommittee of DACC.

Table 5. Edition 2 Development Committee

Name	Company	Organization Represented
Akin Akinseye	AER	Regulator
Sara Proctor (co-chair)	Liberty Energy Canada	Enserva
Kolton Chapman	ARC Resources	CAPP
Steele De Paoli	Tronic Data	CAPP
Gary Ericson	Saskatchewan Ministry of Energy & Resources	Regulator
Andrew Evans	Tourmaline	CAPP/EPAC
Craig Fulowski (co-chair)	Aspenleaf Energy	EPAC
Michelle Gaucher	BCER	Regulator
Matthew Gunn	Step Energy Services	Enserva
Cathleen Hearn	Saskatchewan Ministry of Energy & Resources	Regulator
Max Jorgenson	Trican	Enserva
Ashley Kalenchuk	Ovintiv	CAPP
Addison Kowal	White Cap Resources	CAPP
Ryan Moore	Saskatchewan Ministry of Energy & Resources	Regulator
Daniel Owens	Trican	Enserva
Oddie Peddie	Step Energy Services	Enserva

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Name	Company	Organization Represented
Geoff Pucket	Tundra Oil and Gas	EPAC
Andrew Robertson	AER	Regulator
Bruce Sendecki	AER	Regulator
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Edition 1

The first edition of IRP 24 was developed April 2016.

Include the development committee if available.

Jeff Saponja (nee TriAxon Oil Corporation) and Ron Gusek (nee Sanjel) kept us on course through the rapid development of the first stage of the IRP, Interwellbore Communication. Following sanction of Interwellbore Communication, Ron Gusek continued the journey and was joined by Dean Tymko (nee Penn West Petroleum Ltd.). Ron handed his torch and oars to colleague James Gray. James and Dean captained our quest through to the industry review. Dean tossed his oars and torch to Kevin Matiasz (nee Encana) who helped us sail through to the last leg.

From start to finish Camille Jensen stood firm in the role of helmsman and acted as our technical writer. Manuel Macias and Andy Reimer at Enform provided an anchor and kept us afloat by administering the project.

There were several key individuals that comprised our development team and our review teams. This project would have been impossible without the following great minds that joined us at the work group table regularly: Alexey Zhmodik, Schlumberger; Barry Hlidek, Baker Hughes; Clint Olmstead, Conoco Phillips; Dan Belczewski. Bissett Resource Consultants Ltd.; Dean Tymko, Penn West Petroleum Ltd.; Dean Hillenga, Millennium Stimulation Services; Doug Pipchuk, Schlumberger; Eric Tudor, GasFrac; Fred Boyko, Schlumberger, Garnet Olsen, Canyon Technical Services; Greg Brown, Gasfrac; James Gray, Sanjel; Jonathan Heseltine, C-Fer Technologies; John McNaughton, Trican Well Services; Kevin Matiasz, Encana; Kyle Pisio, Canadian Natural Resources Ltd.; Mark Willis, Canadian Natural Resources; Marty Muir, Husky Energy Inc.; Mike Langill, Nabors Well Services Canada Ltd.; Rick Theissen, Conoco Phillips Canada; Ron Saunders, Imperial Oil Resources; Ryan McDowell, Crescent Point Energy Trust; Stacey Yuen, C-Fer Technologies; Steve Mueller, Birchcliff Energy.

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Thank you to the employers of all our Subject Matter Experts. Your support in sharing your technical leaders, your meeting rooms, and dedicated presence through the development and review process did not go unnoticed and is representative of your support for the project and its published recommended practices. We would like to extend our appreciation to FMC Technologies and Sanjel Corporation for the use of their Board Rooms for regular Committee meetings. We appreciated these rooms were well appointed, centrally located and offered our group a neutral place for open discussion.

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Appendix B: Case Studies

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Case Study #1 At Risk

Introduction

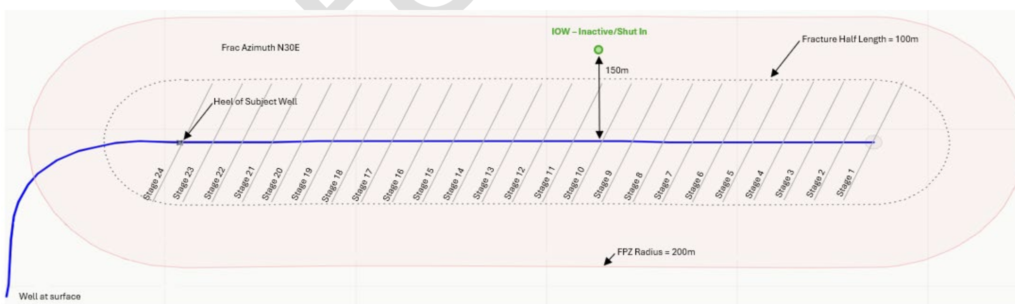
The Interwellbore Communication Hazard Management Process identified an Identified Offset Well (IOW) within the Fracture Planning Zone (FPZ) that required a risk assessment. The IOW, shown in Map view below, is a commingled oil-producing well that has been shut in for six years due to high operating costs and unfavorable economics. Although approved for abandonment, field work has not yet been completed.

Subject Well Information	
Producing Formation	Lodgepole
TVD (m)	817
X_f (m)	100 (estimated by GOHFER® fracture model)
Z_f up (m)	7 (estimated by GOHFER® fracture model)
Z_f down (m)	26 (estimated by GOHFER® fracture model)
Maximum Surface Pressure (MPa)	38
Fracture Design	24 Stages, 10T/ Stage, 1.6m^3/min, borate cross-link fluid system

Determine Identified Offset Wells (IOWs)

Fracture Planning Zone (FPZ)

Plan View



At-Risk IOW Barrier Analysis

Risk Categories	Description
H_2S Content	None Detected
Inactivity Duration	Inactive 6 years. Last production Oct 2018. Status: Shut-In
Well Type	Oil Production. Commingled (Bakken & Lodgepole) Vertical
Well History	January 16, 1986: Original Lodgepole Completion - 12T 20/40 sand frac September 16, 1987: Recompletion: Perforate: 815.8 - 822.4 mKB & 16T 20/40 sand frac. September 30, 1994: Recompletion Deepen - Bakken Target: Deepen well to 925 mKB. RIH 10jts 88.9 mm liner and cement from 827.1-923.4 mKB. Perforate Bakken: 914.7 - 917.2 mKB. Frac: 4T 20/40 sand.

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At-Risk IOW Barrier Analysis

Wellbore Construction and Integrity	Surface Casing (SRF CSG): 219.1 mm, 30.72 kg/m, 0.75 m^3 cement returns to surface. Production Casing (PRDN CSG): 139.7 mm, 23.07 kg/m, 2.5 m^3 cement returns. Total Depth (TD): 893 mKB. PBTD: 882.35 mKB Lodgepole Perfs: 139.1 mm casing (CSG) Event (1) 836 – 839 mKB, 12T Frac; Event (2) 815.8 - 822.4 mKB, 16T Frac Bakken Perfs: 88.9 mm Liner 914.7 - 917.2 m KB, 4T Frac PRDN Casing Integrity is unknown due to well age, inactivity, and lift equipment corrosion history.
Well Location	Not close to any water body, slough or significant low-lying areas.
Reservoir Pressure	Subnormal < 9.8 kPa/m, assume low reservoir pressure, unable to flow to surface.
Wellbore Fluids	Suspect corrosion. History of scale. LDGPL: 50% water cut (WC), no measurable gas but expect high gas to oil ratio (GOR) from area experience, Bakken (BKKN): 85% WC, no measurable gas.
Offset Stimulation Interference	Hydraulic Fracture - Estimated fracture 1/2 length (X_f) 100 m. FPZ outer boundary is 200 m from wellbore center.
Enhanced Recovery Scheme	No waterflood or disposal wells (LDGPL) in FPZ.
Subsurface Production Equipment	60.3 mm tubing, no anchor, landed depth 919.56 m. 1.5 in bottom hole pump and 19 mm rods.
Surface Equipment	14 MPa wellhead. Rod BOPs (Ratigans) rated at 10 MPa. Wellhead slip stream side has a flexible hose and unknown condition and pressure rating. Pumpjack present. Flowline well but inactive for several years and condition unknown.

IOW Risk Assessment

FPZ Well Identification	Identified Offset well (IOW). Well is within 2 x_f (X_f = 100m).
Risk Assessment	At-Risk – IOW is penetrating the target zone as subject well horizon.
Risk Assessment Justification	The offset distance from the subject well center-to-center is 150 m. Based on historical operator experience in the area, there is a high likelihood of a high magnitude IOW fracture hit event. The IOW Barrier Analysis identified the ratigans (rod BOPs) and a flexible wellhead hose of unknown condition as potential areas of concern. The production casing has cement to surface and the well location is not close to any water body, slough, or significant low-lying area. The environmental impact risk is very low.

IOW Control Plan

The control plan is to keep the well shut in with the ratigans (rod BOPs) closed and employ live, electronic casing pressure monitoring during the subject well fracture operation. If the casing pressure rate of change is > 10 kPa/min, the fracture operation will cease and move to flush the zone. The fracture port/sleeve will be closed immediately afterwards. The maximum allowable IOW wellhead pressure rating is derated to 3500 kPa (500 psi) due to age and the unknown condition of the surface equipment.

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Case Study #2 At Risk

Introduction

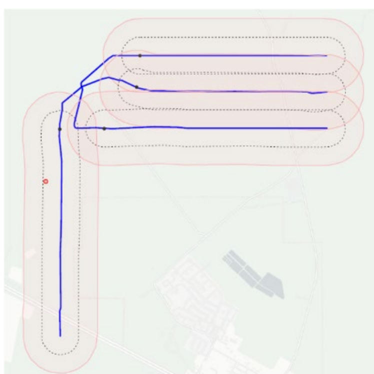
The subject well operator identified an abandoned offset well within the FPZ of one lateral on a four- well pad. The offset well was drilled through the zone of interest and abandoned using multiple cement plugs. The well was cut and capped, leaving no means to monitor pressures during the hydraulic fracture operation.

Subject Well Information	
Producing Formation	Duvernay
TVD (mKB)	3018
X_f (m)	300
Z_f up (m)	50
Z_f down (m)	30
Maximum Surface Pressure (MPa)	76
Fracture Design	Slickwater fluid system., plug and perforation

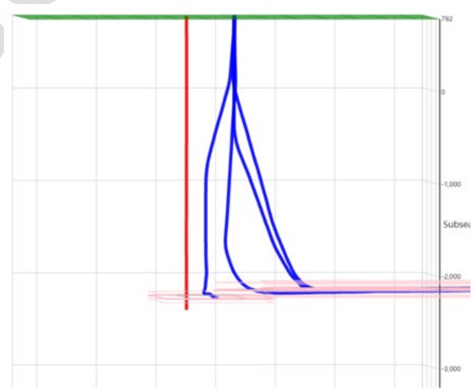
Determine Identified Offset Wells (IOWs)

Fracture Planning Zone (FPZ)

Plan View



Horizontal View



At-Risk IOW Barrier Analysis

Risk Categories	Description
H_2S Content	0.00%
Inactivity Duration	65 years
Well Type	Abandoned. (Cardium formation)
Well History	<u>Nov 15, 1957</u> – Spud <u>Nov 17, 1957</u> – Run and Cement Surface Casing <u>Jan 6, 1958</u> - TD vertical well 3189mkb <u>Jan 15, 1958</u> – Set Cement Plugs: (1) 3121-3189mkb, (2) 2350-2402mkb, (3) 2048-2018mkb, (4) 1567-1627mkb <u>Jan 16, 1958</u> – Run and Cement Production Casing <u>Jan 19, 1958</u> – Perforate 1192-1200mkb. Run tubing and packer. <u>Jan 21, 1958</u> – Hydraulic Fracture with 13.6MT 20/40 sand. Swab well for several days, deemed non-productive.

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At-Risk IOW Barrier Analysis	
	Jan 28, 1958 – Set cement plug (5) 1169-1210mkb. Free-point 177.8mm at 1036mkb. Jet cut casing at 1037mkb and retrieve. Leave 189m casing in the hole. Pump cement plug (6) 268-241mkb. Tag cement top 245mkb with tubing. Pull tubing, fill mouse hole, rat hole and top 3m of casing with cement. Cut casing 1m below ground, weld ¼" plate on casing and back fill. Well Abandoned.
Wellbore Construction and Integrity	Surface Casing: 273.1mm, 60.26kg/m, J-55 to 253mkb. Cement returns to surface Production Casing: 177.8mm, 29.76kg/m and 34.22kg/m, J-55 to 1224mkb. No cement returns to surface. Free-Point at 1036mkb, cut and removed 848m. Open hole: 228.6mm, 1224mkb to 3189mkb
Well Location	Northern Alberta
Reservoir Pressure	~12MPa (normally pressured)
Wellbore Fluids	Fresh Water between cement plugs
Offset Stimulation Interference	Hydraulic Fracture – IOW is open hole, drilled through subject well's stimulation zone
Enhanced Recovery Scheme	None
Subsurface Production Equipment	N/A, cut and capped and reclaimed
Surface Equipment	N/A, cut and capped and reclaimed

IOW Risk Assessment	
FPZ Well Identification	Identified Offset well (IOW) within 2 x_f (X_f = 300m).
Risk Assessment	At-Risk – IOW is penetrating the target zone.
Risk Assessment Justification	The offset distance from the subject well center-to-center is 256 m. Based on historical operator experience in the area, there is a high likelihood of an IOW frac hit event. The IOW Barrier Analysis identified adequate hydraulic isolation from the (6) cement plugs set during abandonment, however with no wellhead installed it would not be possible to monitor the IOW during frac. The production casing does not have cement to surface and the well location is not close to any water body, slough, or significant low-lying area. The environmental impact risk is very low.

IOW Control Plan

The location was visually scouted prior to fracture operations. The operator elected to reduce slurry volumes by 50% of (3) stages nearest the offset well to reduce the fracture half-length and possible communication event(s). During operations the location was visually spot checked as well as at the conclusion of the job. There were no indications that a communication event had occurred.

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Case Study #3 IOW modified to At Risk IOW

Introduction

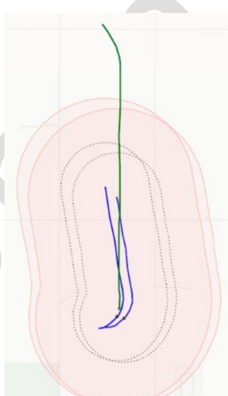
An existing producing Charlie Lake well, overlying a new pad completion in the Montney, encountered unexpected pressures during fracturing operations of the Montney wells. The Charlie Lake well was subsequently shut in for the duration of the Montney fracturing operations. The lateral distances between the wells varied up to 150 m. The Montney operator identified an FPZ radius in this area of 1500m (twice the modelled X_f), which meant the Charlie Lake well would have originally been in the FPZ. The Charlie Lake well is approximately 200mTVD above the Montney wells and does not penetrate the Montney. Fracture modelling predicted that the uppermost fracture height from a Montney frac would have still be more than 200m below the Charlie Lake well. Based on this, the Montney operator did not initially identify the Charlie Lake well as an “at risk” IOW.

Subject Well(s) Information	
Producing Formation(s)	Montney F & G
TVD (mKB)	2397 & 2453
X_f (m)	750
Z_f up (m)	74 (2340 mKB) & 34 (2432 mKB)
Z_f down (m)	58 (2472 mKB) & 48 (2514 mKB)
Maximum Surface Pressure (MPa)	78
Fluid System	Slickwater

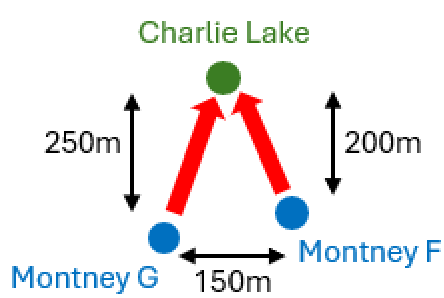
Determine Identified Offset Wells (IOWs)

Fracture Planning Zone (FPZ)

Plan View



Gun Barrel View



At-Risk IOW Barrier Analysis	
Risk Categories	**Description**
H_2S Content	0.00%
Inactivity Duration	Active - On production
Well Type	Pumping – Oil (Charlie Lake)
Well History	Drilled hz and completed with multistage fracs in 02/2020

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Wellbore Construction and Integrity	Surface Casing: 219.1 mm, 35.7 kg/m, H-40 to 158 mkb. Production Casing: 114.3 mm, 14.1 kg/m, J-55 to 1624 mkb.
Well Location	Northern Alberta
Reservoir Pressure	< 21 MPa (virgin) as it is on pump
Wellbore Fluids	Oil
Offset Stimulation Interference	Hydraulic Fracture – Estimated fracture half length (xf) is 750, FPZ outer boundary is 1500 m (2xf)
Enhanced Recovery Scheme	None
Subsurface Production Equipment	Sucker Rod Pump
Surface Equipment	Sucker Rod Pumping System with Low Pressure Stuffing Box

IOW Risk Assessment

FPZ Well Identification	Identified Offset well (IOW) within 2 x_f (X_f = 750m).
Risk Assessment	Minimal Risk - IOW is not penetrating the target zone or the expected subject well vertical fracture geometry - IOW TVD is 136m shallower that predicted fracture height top (see below) - Max z_f up = 2340 mKB TVD, Max z_f down = 2514 mKB TVD - IOW = 2133 mKB TVD
Risk Assessment Justification	Although the IOW was in the FPZ, it was not penetrating the target Montney zones. Frac modelling predicted that the Montney fracs would still be > 200 m lower TVD that the IOW well. Frac hits between the Montney and Charlie Lake were not observed previously. Microseismic showed very small number of Montney frac events overlapping Charlie Lake.

IOW Control Plan

No well control plan was initiated as the IOW was determined as Not at Risk.

Revised IOW Risk Assessment

FPZ Well Identification	Identified Offset well (IOW) within 2 x_f (X_f = 750m).
Risk Assessment	At Risk - IOW is not penetrating the target zone or the expected subject well vertical fracture geometry however: - Unexpected frac hits were encountered on producing IOW during subject well Montney frac operation - Farthest Charlie Lake frac hit was noticed 209m laterally away from Montney - Other operators have seen similar frac comm since Therefore, FPZ needs to be expanded to accommodate any Charlie Lake wells within a 500m radius of a planned Montney frac stage (2 x further distance of frac hit @ 209m rounded up to 250m)
Risk Assessment Justification	Even though the IOW was not penetrating the subject well target, nor the shallowest modeled frac z_f, frac communication was seen.

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Revised IOW Control Plan

1) Early, ongoing 2-way communication between operators to coordinate plans (2-week frac notice leaves little time for well intervention, if the mutually-agreeable well control plan necessitates modified barriers)
2) Establish a primary barrier in all Charlie Lake wells, with minimum pressure rating of 35 MPa, within 500m radius of Montney stage (2 x farthest observed frac hit = 418m, limited dataset of MTNY to CHLK hits, so may be under-estimating the 209m

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Case Study #4 Minimal Risk

Introduction

The subject well operator identified a producing offset well, licensed to a different operator, within the FPZ of the subject well. The offset well was drilled to a depth shallower than the zone of interest.

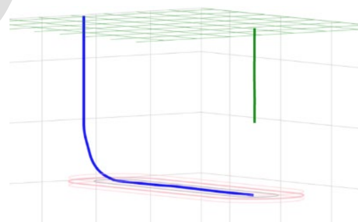
Subject Well Information	
Producing Formation	Wabamun
TVD (mKB)	2164
X_f (m)	206 (estimated by GOHFER® fracture model)
z_f up (m)	55 (estimated by GOHFER® fracture model)
z_f down (m)	8 (estimated by GOHFER® fracture model)
Maximum Surface Pressure (MPa)	63
Fracture Design	50 stage, 25T/Stage 6 m3/min HVFR fluid systemGine

Determine Identified Offset Wells (IOWs)

Fracture Planning Zone (FPZ)

Plan View

Vertical 3D View



IOW Risk Assessment	
FPZ Well Identification	Identified Offset well (IOW) within 2 x_f (X_f = 206m).
Risk Assessment	Minimal Risk
Risk Assessment Justification	This IOW is within the FPZ of the subject well, however it is 540m shallower than the subject well. Fracture height in the upward direction is expected to be 55m and therefore there is minimal risk of fracture communication. For this reason this IOW is deemed to be minimal risk.

At-Risk IOW Barrier Analysis

Not Required

IOW Control Plan

Not Required

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Case Study #5 At Risk SIMOPs

Introduction

During fracture stimulation activities, the scope changed to include remedial service rig operations.

- The original plan was to energize the horseshoe trunk around all eight wells and begin fracturing Pod #2 (Wells #5-#8).
- Service rig work was identified as necessary on well #8 before proceeding with fracturing.
- Service rig work would have people working in/close to the 8m hot zone of the energized trunkline.
- The risk of proceeding with the original fracture schedule was deemed unacceptable due to surface hazards that could not be adequately controlled. No downhole fracture interference was anticipated between Pod #1 & Pod #2 based on drill path and fracture azimuth.
- The lease layout was revised to isolate the trunk line to Pod #1 (Wells #1-#4), eliminating the identified surface hazard and enabling work to proceed safely.
- Auxiliary equipment and lines were relocated to create a safe workspace for service rig operations on well #8, ensuring that simultaneous fracturing operations on Pod #1 did not create unacceptable risks.
- Additional day and night shift supervision was assigned to the service rig to maintain fracture stimulation supervision expectations.
- Fracture operations commenced on wells #1-#4 (Pod #1) while service rig work proceeded on well #8 (Pod #2). Company SimOps protocols were followed, new risks were identified and controlled, and the Chief Fracturing Supervisor was designated as Chief Onsite Supervisor for emergency response.
- Once well #8 repairs were completed, all eight wells (Pod #1 and Pod #2) were tied into the common trunk line and fracture operations continued as originally planned.

Risk Assessment

Hydraulic fracture operations conducted concurrently with remedial service rig work on same pad.

Figure 20. Risk Assessment

Risks / Scenarios	Severity Rating	Severity Reasoning	Likelihood Rating	Likelihood Reasoning	Overall Risk level	Required Controls to Reduce Risk	Outcome
High Pressure Piping Failure	Critical	High pressure, spill/release	Unlikely	Inspected piping, piping rated for wellbore pressure, sand presence, pressure testing	High Risk	- Follow proper installation sequence and ensure all equipment in good working order. - Pressure test and purge high pressure piping. - Utilize engineered restraints with Engineered anchor points - ESD off wellhead prior to any flow directional changes with pneumatic control. - Spotters while moving equipment near equipment. -*Additional control to isolate Pod 2 from frac during service rig work ensuring safe distance from hot zone to safely execute work.	**Safe to proceed with additional controls - Isolating Pod 2 piping from frac thus removing hot zone from service rig work area**
Moving equipment & multiple crews	Serious	Restricted work, medical aid, equipment damage, trigger another failure/risk scenario	Unlikely	Good communication, identifying restricted work areas, good lighting, well-marked lease layout	Medium Risk	- Workers not to access restricted zones discussed and identified in daily safety meeting - Follow spotter policy and procedures - Look both ways prior to crossing areas with traffic and ensure you are visible - Do not work under suspended loads, do not leave your work area. - Ensure to always remain visible around heavy equipment and wear clothing to assist in being visible. - High risk areas should be well marked & signage present	Safe to proceed with controls – Medium Risk
Flaring onsite causing fire/explosion	Serious	Damage to equipment, lost time injury due to fire/explosion	Unlikely	Flares spaced out as per OGC regulations	Medium Risk	- Follow OGC recommended spacing - Communicate between OSS's when flaring - Discuss alarms present to identify emergency - Following service providers safe operating procedure during flaring operations - Ensure no equipment is mobilized near flaring equipment causing spacing issues.	Safe to proceed with controls – Medium Risk
Downhole communication	Moderate	Loss of well control, washouts, spill/release	Unlikely	Geological features decrease likelihood, No seismicity potential, Wellbore trajectory not on azimuth with frac	Low Risk	- Follow all well control practices ensuring equipment adequate, functional and personnel trained - Have Frac Planning Zone (FPZ) evaluated and signed off to ensure frac azimuth and wellbore trajectories are eliminated between Pod #1 and Pod #2 - Internally review and confirm seismicity potential including applicable fault mapping ensuring no potential for off-azimuth fracture growth	Safe to proceed with controls – Low Risk

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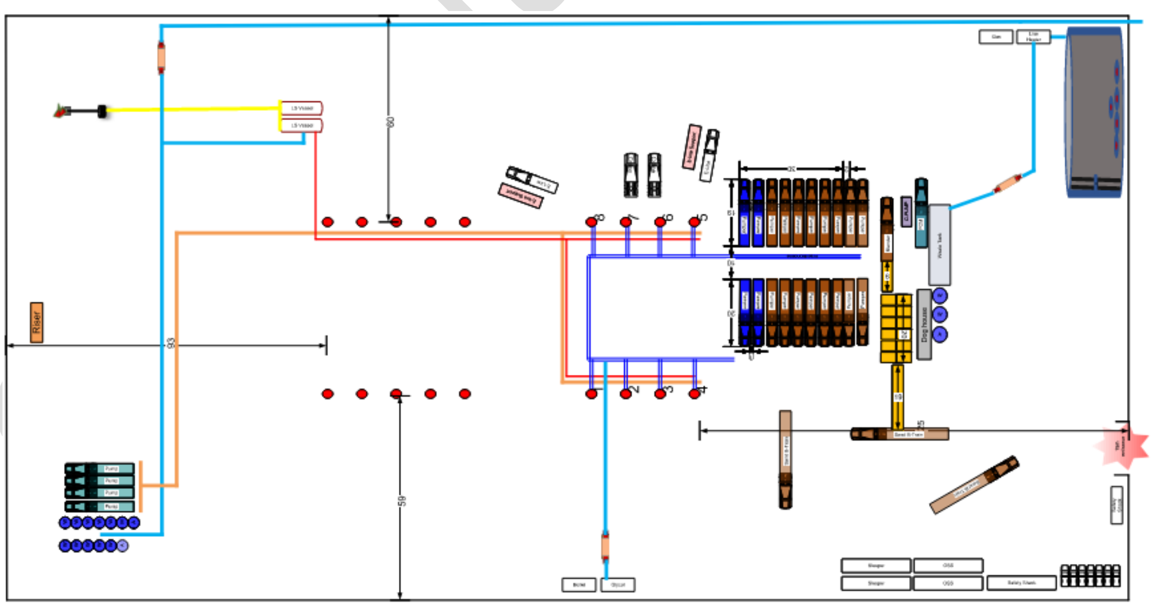
Outcome: Completions activities can be safely conducted during remedial service rig work if Pod #2 is isolated. Once the service rig work is complete, Pod#2 completions can resume and the hot zone reinstated.

Figure 21. Aerial View of Surface Operations Layout

Figure 22. Surface Operations Schematic



Appendix C: Subject Wellbore Schematics

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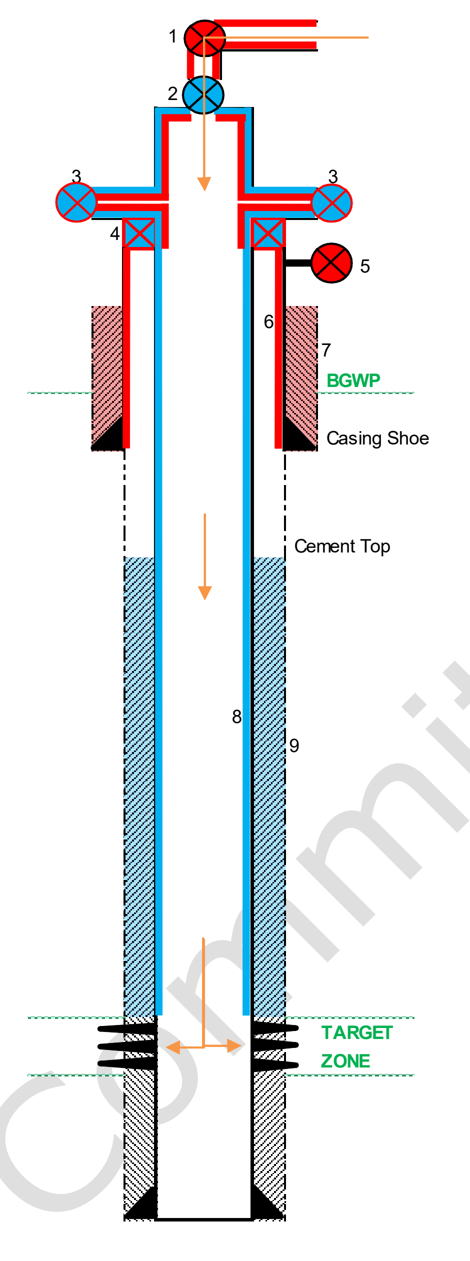
Figure 23. Sample Subject Well Fracture Stimulation Through Casing Schematic

Subject Well



* O = Open, C = Closed

Well Barrier Element (WBE)	OEM Capacity (MPa)	Adjusted Max Pressure (MPa)	WBE Status *(O / C)
Primary Barrier Envelope			
2. Wellhead isolation valve			
3. Casing valve			
4. Wellhead (Production casing seals)			
8. Production casing (burst)			
9. Production casing cement			
Secondary Barrier Envelope			
1. Pumping company valve			
3. Casing valve			
4. Wellhead (Production casing seals)			
5. Surface casing valve			
6. Surface casing (burst)			
7. Surface casing cement			
Surface casing shoe (FIT)			

Direction of Flow : →

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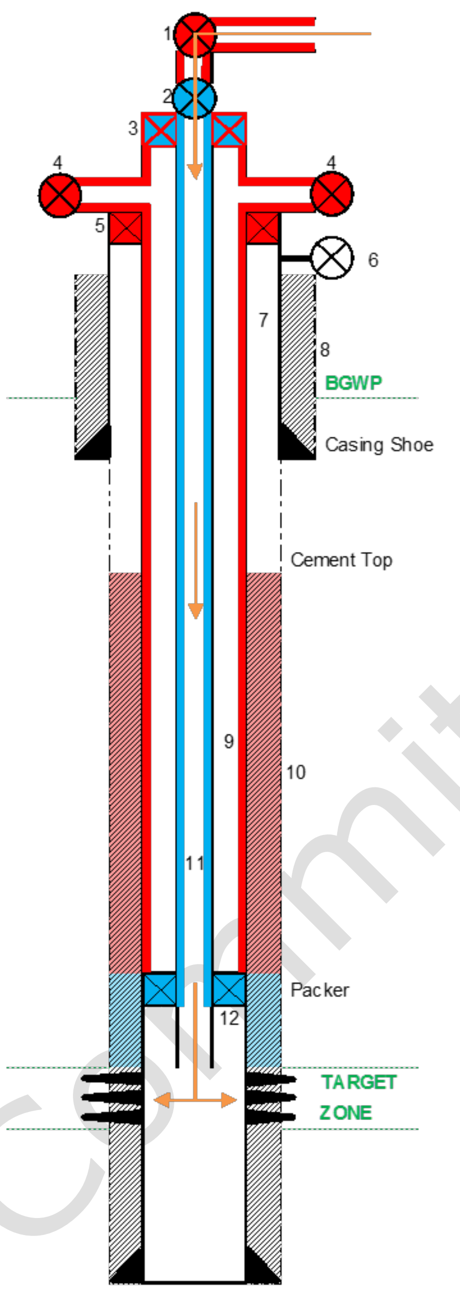
Figure 24. Sample Subject Well Fracture String Completion Schematic

Subject Well



* O = Open, C = Closed

Well Barrier Element (WBE)	OEM Capacity (MPa)	Adjusted Max Pressure (MPa)	WBE Status *(O / C)
Primary Barrier Envelope			
2. Wellhead isolation valve			
3. Tubing hanger seals			
11. Tubing (burst)			
12. Packer			
9. Production casing (burst)			
10. Production casing cement			
Secondary Barrier Envelope			
1. Pumping company valve			
3. Tubing hanger seals			
4. Casing valve			
5. Wellhead (Production casing seals)			
9. Production casing (burst)			
10. Production casing cement			

Direction of Flow: →

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Appendix D: Casing Burst and Collapse Considerations

IRP 24 presumes that a well design and casing are in place before developing a fracture stimulation program. Reviewing the existing well design and casing is essential to understand the limitations of the pipe and connections.

For new wells, the design and casing are selected to accommodate all expected activities over the well's life cycle, including drilling, completion, fracture stimulation, production and abandonment. A life cycle approach ensures the well is designed for all activities–not only the stimulation.

Factors Influencing Maximum Allowable Loads

The following factors may reduce the maximum allowable load below the OEM pressure rating:

- Axial loads–from gravity, drag placing pipe, tension when setting slips, thermal expansion/contraction, varying stimulation fluid temperature / density, and axial-hoop forces from internal pressure
- Faulting, such as shear or pressure communication
- Erosion
- Corrosion
- Partial pressure (pp) H_2S–influences barrier metallurgy requirements or performance
    - pp $H_2S < 0.3$ kPa (Minimum Safety Factor Burst = 1.10)
    - $0.3 \leq$ pp $H_2S \leq 10$ kPa (Minimum Safety Factor Burst = 1.20)
    - pp $H_2S > 10$ kPa (Minimum Safety Factor Burst = 1.25)

Note: The H_2S partial pressure thresholds and associated minimum safety factors for burst are aligned with the following standards:

- Partial Pressure Thresholds (0.3 kPa and 10 kPa): Derived from ANSI/NACE (now Association for Materials Protection and Performance AMPP) -MR0175-2021/ISO 15160:2020 Petroleum and Natural Gas Industries-Materials for Use in H_2S-Containing Environments in Oil and Gas Production. The 0.3 kPa limit is the globally recognized threshold for defining "sour service" (Region

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1). The 10 kPa limit corresponds to the transition between severity regions for carbon and low-alloy steels.

  - Safety Factors (1.10, 1.20, 1.25): While API TR 5C3 establishes the baseline burst calculation and a general 1.10 safety factor for sweet service, the tiered increases (1.20 and 1.25) are regional requirements established by the AER (Directive 10) and DACC. These factors provide an additional engineering margin to account for the reduced ductility and increased failure risk of materials in higher-concentration sour environments.

- Bending loads–from wellbore trajectory, Dog Leg Severity (DLS), or axial buckling
- Torsion load
- Thermal load–from changes in tubular temperature during operations
- Temperature effects–including changes to casing material properties and loading
- Hydraulic isolation–related to cement integrity

Barrier Metallurgy

The casing material is selected to suit both planned fracturing operations and the expected production period. Consider whether the well will be

- sweet for its entire life–see API 5CT, API TR 5C3 or AER D010 for acceptable casing materials
- sweet during fracture operations but potentially sour during production–see AER D010 for casing material recommendations
- sour during both fracture operations and production–AER D010 casing materials required. IRP 1 specifies casing materials for critical sour wells or pp H_2S > 3500 kPa

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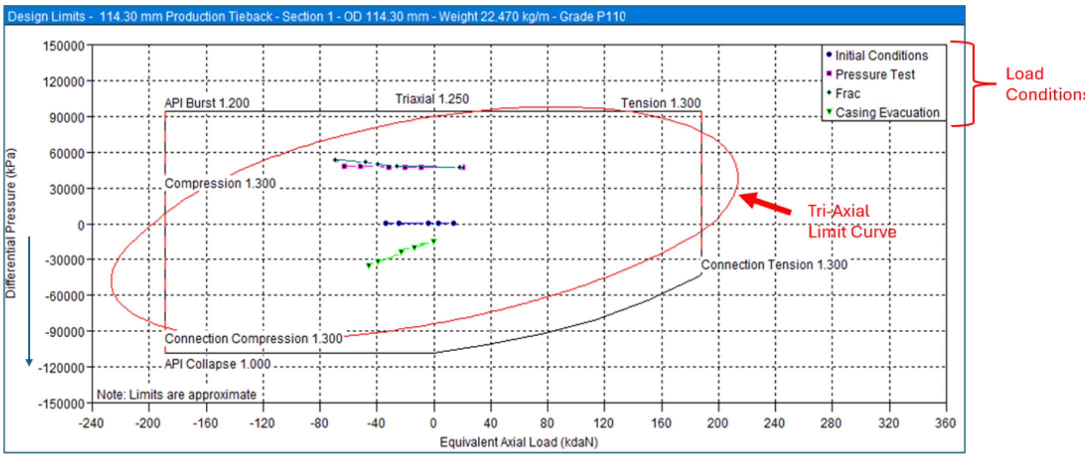
Tri-axial Load Model Examples

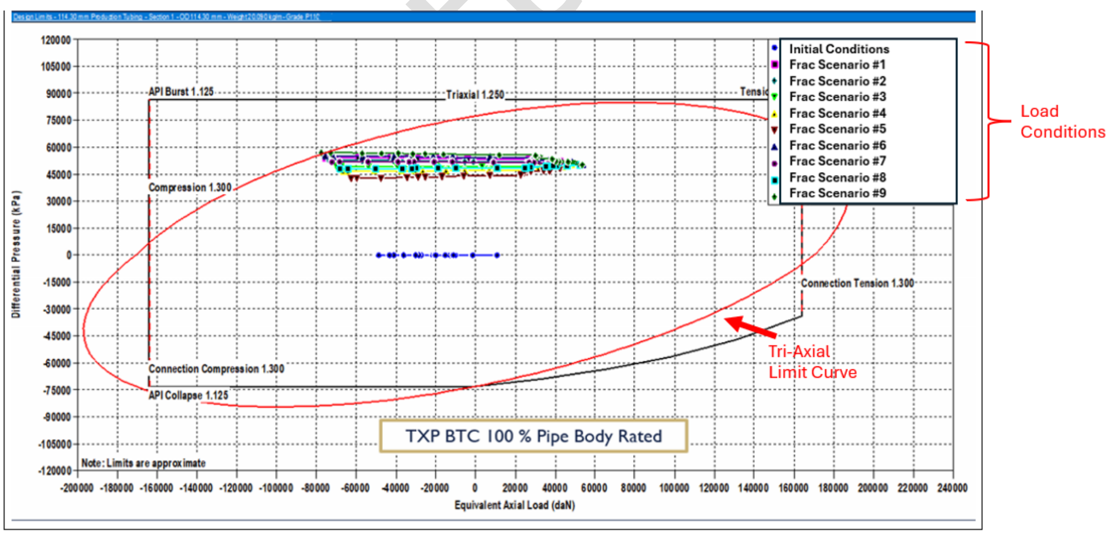
Figure 25. Example of Load Analysis Demonstrating All Load Cases are Within the Design Envelope.



Von Mises Ellipse Model Example 1: Fracturing a Water Disposal Well down a 114.3 mm Tieback

- If any load condition curve crosses the tri-axial limit curve (ellipse) then the triaxial design criteria is exceeded
- This current well design is OK for all expected load conditions

Figure 26. Example of Load Analysis Demonstrating Load Cases Exceed the Design Envelope



Von Mises Ellipse Model Example 2: Fracturing a Hz Production Well down a 114.3 mm Tieback

- If any load condition curve crosses the tri-axial limit curve (ellipse) then the tri-axial design criteria is exceeded
- Frac Scenario #9 exceeds design criteria
- Load conditions and/or well design needs to be modified.

Calculations

The calculations below show how to determine burst and collapse Adjusted Maximum Pressure (AMP) ratings and planned pressure loading.

Barrier Element Burst and Collapse

Considering the factors above, barrier element burst and collapse may be calculated as described below (see footnotes above for additional references). In these equations, OEM refers to Original Equipment Manufacturer rating.

Equation 1. Barrier Element Burst

$$\textit{Barrier Element Burst}_{AMP} = \textit{OEM Burst - Burst reduction due to factors above}$$

Equation 2. Barrier Element Collapse

$$\textit{Barrier Element Collapse}_{AMP} = \textit{OEM Collapse - Collapse reduction due to factors above}$$

Envelope Burst and Collapse

The envelope is one or more barrier elements preventing unintended fluid flow from the formation into the wellbore, into another formation, or to the external environment. Envelope AMP may be calculated as described below:

Equation 3. Envelope Burst

$$\textit{Envelope Burst}_{AMP}\ (EB_{AMP}) = \textit{Lowest Barrier Burst}_{AMP}$$

Equation 4. Envelope Collapse

$$\textit{Envelope Collapse}_{AMP}\ (EC_{AMP}) = \textit{Lowest Barrier Collapse}_{AMP}$$

Maximum Burst and Collapse Pressures

Maximum burst and collapse pressures for the fracture stimulation design can be calculated using the following:

Equation 5. Burst Pressure

$$\textit{Burst Pressure}_{max} = STP_{max} + HDP_{max} + \textit{Pulse Pressure}$$

Equation 6. Collapse Pressure

$$\textit{Collapse Pressure}_{max} = BHTP - HP_{min}$$

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Maximum Surface Treating Pressure

Maximum surface treating pressure (STP_{max}) depends on the set point and the type of stop pumping control or relief system:

Equation 7. Operator Controlled (Manual Stops)

$$STP_{max} = Set\ Stop\ Pump\ Pressure + Reaction\ Time\ Error$$

Equation 8. Electronic Controlled (Instrument Stops)

$$STP_{max} = Set\ Stop\ Pump\ Pressure + Instrument\ Error$$

Equation 9. Mechanical Relief

$$STP_{max} = Set\ Mechanical\ Relief\ Pressure + Instrument\ Error$$

Variables in the equation above are defined as follows:

STP_{max}	Maximum Surface Treating Pressure (just before screen out)
$BHTP$	Bottom Hole Treating Pressure (Fracture pressure plus pressure losses outside the envelope (e.g. tortuosity, perforation friction)
HP_{min}	Minimum Internal Hydrostatic Pressure (calculated from the lesser of base fluid density or flowback gas column)
HP_{max}	Maximum Internal Hydrostatic Pressure (calculated from the highest slurry density)
HDP_{max}	The maximum hydrostatic pressure difference at any depth between HP_{max} and the estimated formation pressure of any exposed permeable zone.
Pulse Pressure	The result of the change in fluid momentum and depends on the velocity, density, and time for the fluid to decelerate or stop. Barrier (e.g., casing string) expansion, fluid compressibility and leak-off will reduce pulse pressure.

Note: Electronic or manual shut down or mechanical relief pressure is typically set a few MPa higher than the anticipated surface working pressure.

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Appendix E: Modeling Fracture Half-Length & Fracture Height

For Interwellbore Communication Assessment, the fracture half-length (x_f) and fracture height (z_f) are defined. These are most commonly determined through hydraulic fracture simulation or modeling.

Fracture half-length (x_f) is the lateral distance in the horizontal plane, measured orthogonally from the subject well to the outer tip of a fracture propagated during stimulation. It represents the maximum extent of subsurface influence by an induced fracture.

Fracture height (z_f) is the vertical extent of fracture growth, measured both upward and downward. Unlike x_f, z_f is not assumed to be symmetrical around the subject well wellbore and therefore independent values are assigned for upward and downward growth. Fracture height cannot always be assumed to be limited by caprock above the target zone.

Although x_f and z_f are estimates, over or underestimating either dimension carries operational risk. Reasonable estimation requires a combination of log measurements, physical measurements, and/or meaningful statistical datasets from comparable wells.

Data Sources for X_f and Z_f Modeling

A log suite may include the following:

- Triple combo (gamma ray, density and neutron) or dipole sonic
- Supplementary measurements such as geomechanical rock properties, fracture image logs, seismic, fluid efficiency
- Accurate reservoir properties such as pressure, porosity, and permeability

Additional fracture propagation measurements can include the following:

- Offset pressure
- Micro-seismic
- Deformation (tiltmeters)

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- Historical data for fracture model calibration

Scenarios and Parameters Leading to Over or Underestimation of X_f or Z_f

1. Model Parameters
    - Reservoir properties: porosity, permeability, reservoir pressure, pay height, lithology, presence of natural fractures
    - Geomechanical properties: Poisson's Ratio, Youngs Modulus, principal stress regime and magnitudes
    - Closure stress in bounding layer (stress contrast)
    - Increase in Young's modulus with applied stress during pumping (induced stiffening)
2. Pressure Pumping Design Parameters
    - Treatment rate
    - Total fluid volume
    - Fluid rheology (i.e. viscosity)
    - Fluid leak-off
    - Proppant type and amount
3. Additional Parameters
    - Reservoir depletion within the zone of interest
    - Structural complexity (existing faults or fractures)
    - Stress anisotropy (σh_{min} vs. σh_{max})
    - Horizontal bedding plane failure (fracture containment due to difficulty propagating vertically)
    - Induced fracture complexity
    - Offsetting wells or ghost holes near preferential fracture azimuth
    - Multiple fractures taking fluid, with only one receives the total volume
    - Subject well integrity

Note: All models carry uncertainties, limitations, and variability, particularly in areas with complex geology or limited historical data. Validation with real x_f and z_f measurements is critical.

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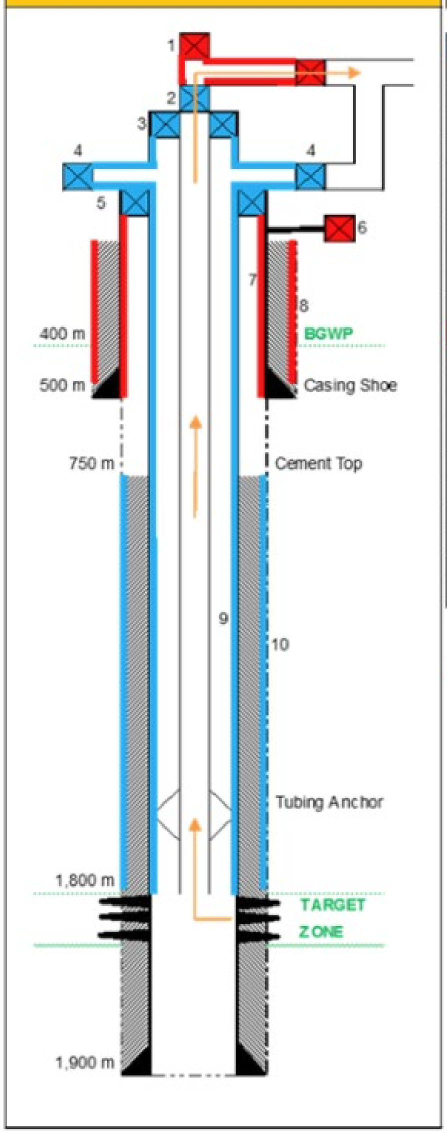
Appendix F: Sample IOW Barrier Schematic

Figure 27. Sample IOW Barrier Schematic

Identified Offset Well



Barrier Elements	OEM Capacity (MPa)	Adjusted Max Pressure (MPa)	Barrier Status *(O / C)	IOW Monitored (Y / N)
Primary Barrier Envelope				
2. Rod BOP				
3. Tubing hanger seals				
4. Casing valve				
5. Secondary seals				
9. Production casing				
10. Production Casing Cement				
Secondary Barrier Envelope				
1. Stuffing box				
6. Surface casing vent valve				
7. Surface casing				
8. Surface casing cement				

Direction of Flow : →

BGWP = Base Ground Water Protection

Appendix G: Glossary

The following acronyms and definitions are used in IRP 24.

AER Alberta Energy Regulator

ALARP As Low As is Reasonably Practical

AMP Adjusted Maximum Pressure

BCER British Columbia Energy Regulator

CAPP Canadian Association of Petroleum Producers

DACC Drilling and Completions Committee

ERP Emergency Response Plan

FPZ Fracture Planning Zone

FSHMP Fracture Stimulation Hazard Management Process

ICHMP Interwellbore Communication Hazard Management Process

IOW Identified Offset Well

IRP Industry Recommended Practice

SCW Special Consideration Wellbore

SHMP Surface Hazard Management Process

SW Subject Well

SWIHMP Subject Well Integrity Hazard Management Process

TVD True Vertical Depth

X_f Fracture half length

Z_f Fracture height

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Active Downhole Operations Drilling and well servicing operations (which may include multiple Operators) on any IOW that may occur during the planned fracture stimulation operation on the subject well.

Active Operations Area is the portion of the lease that contains operations and may include an exclusion zone, elevated hazard zone and silica exposure area. The active operations area excludes the safe zone.

Adjusted Maximum Pressure A pressure determined by analyzing a barrier's original manufacturer's equipment specification / rating and then changing this original pressure rating by compensating for age and service. This pressure is determined at the subject well operator's discretion and in alignment with its risk tolerance.

Anisotropy When a material's properties change depending on the direction they are measured. This can happen at any scale, from tiny mineral crystals to large rock formations and often occurs in shales, where flat minerals like micas and clays become aligned during compaction, creating directional layers.

As Low As Is Reasonably Practicable (ALARP) The concept of "reasonably practicable" which involves weighing a risk against the trouble, time and money needed to control the risk or the sacrifice needed to further reduce risk. It describes the level to which we expect to see workplace risks controlled. See the UK HSE document ALARP at a Glance, is available from the UK Government Website.

At-risk IOW An Identified Offset Well (IOW) that penetrates the subject well's target zone or terminates near the subject well's target zone.

Azimuth The angle between the direction of a fracture or wellbore and north, measured on a flat, horizontal surface. It is usually measured in degrees, clockwise from true north or magnetic north. Azimuth helps describe the orientation of fractures or the direction in which it is drilled.

Barrier Element Refers to an individual equipment component or objects that together collectively comprise a barrier envelope.

Barrier Envelope Refers to one or more barrier elements that prevent fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment (see NORSOK D-10).

Blowout An unintended flow of wellbore fluids (oil, gas, water, or other substance) to the surface that cannot be controlled by existing wellhead and/or blowout prevention equipment, or a well that is flowing from one formation to another formation(s) (underground blowout) that cannot be controlled by increasing the fluid density. Control can only be regained by installing additional and/or replacing existing surface equipment

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to allow shut-in or to permit the circulation of control fluids, or by drilling a relief well (see AER Directive 056: Energy Development Applications and Schedules, Appendix 3).

Dual-Fuel describes an engine that operates using two different fuels at the same time.

Elevated Hazard Zone is a designated area within the active operations area where increased risks exist due to the operational activities being performed at the time (e.g., fluid transfer, wireline operations, low pressure equipment, and fueling while pumping).

Energy Well A well initially licensed for the purpose of petroleum energy development, not including water wells.

Exclusion Zone Is a designated area of hazards with the highest risk and requires authorization to enter.

Fracture Azimuth The orientation or direction of a fracture, typically measure as an angle from a reference direction such as true north.

Fracture Half-Length (x_f) The lateral distance initiated from the subject wellbore to the outer tip of a fracture propagated by fracturing. The fracture half-length (x_f) is also the maximum extent of the influence of the subsurface interaction by an induced fracture.

Fracture Height (z_f) The vertical distance of the fracture.

Fracture Planning Zone (FPZ) Defines a screening area around the subject well, making it possible to identify all offset wells proximal to the subject well that may require a risk assessment and a well control plan.

Fracture Stimulation A treatment performed above the fracture pressure of the reservoir formation to create a highly conductive flow path between the reservoir and the wellbore (Adapted from Schlumberger Oilfield Glossary).

Fracture Stimulation Design The creation of a plan for the fracture stimulation of the subject well. It is a process to analyze the set of conditions, needs and requirements to determine fracture geometry that optimizes fracture stimulation objectives.

Fracture Stimulation Program The document that defines the procedures and requirements to meet the fracture stimulation design of the subject well. The fracture stimulation program includes, but is not limited to the following parameters:

- Pressures
- Base fluid types
- Chemicals
- Proppant type, size, concentration and tonnage

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- Rates
- Volumes
- Equipment

Fracture Stimulation Operation The execution of the fracture stimulation program.

Geometry See Hydraulic Fracture Geometry.

Hazard Something (e.g., an object, a property of a substance, a phenomenon or an activity) that can cause adverse effects.

Hydraulic Fracture Geometry The maximum lateral (x_f) and vertical extension (z_f) of hydraulic fluids as a result of fracture stimulation.

Identified Offset Wells (IOWs) All offset wells within the Fracture Planning Zone (EPZ) plus all wells identified as special consideration wells that require evaluation using the IOW Risk Assessment.

Identified Offset Well Operator Refers to the operator of an offset well within the Fracture Planning Zone (FPZ) or special consideration well determined during the IOW Risk Assessment.

IOW Well Control Plan A comprehensive plan developed for at-risk IOW to avoid or control the risk of an uncontrolled well event.

Interwellbore Communication Interwellbore communication is defined as fluid and/or pressure communication event at an Offset Well during a fracture stimulation operation on a subject well.

Iron The terms iron in treating iron, iron management, or fracturing iron refer to the high-pressure tubulars used in fracturing operations. The treating iron extends from the fluid end discharge on the horsepower units to the wellhead. It includes all piping, connections and components (valves, manifolds, straight joints, and swivels, etc.) and is normally made for a minimum of (69 MPa) 10,000 psi Working Pressure.

Licensee (Also known as “permit holder” in BC) The holder of a facility, pipeline, or well license according to the records of the Alberta Energy Regulator (AER); includes a trustee or receiver-manager of property of a Licensee (see AER D056: Energy Development Applications and Schedules, Appendix 3). In Saskatchewan as defined in The Oil and Gas Conservation Act, a licensee means a person who holds a license and includes a trustee or receiver-manager of property of a licensee.

Maximum Treatment Pressure Highest pressure permissible during fracture stimulation operations.

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Minimal risk wells are wells that fall within the topographical FPZ but are not identified as an At-risk well.

Offset Well Any wellbore that is proximal to the subject well.

Orphan Well According to the Orphan Well Association (www.orphanwell.ca), "in the upstream oil and gas industry, an orphan is a well, pipeline, facility or associated site which has been investigated and confirmed as not having any legally responsible or financially able party to deal with its abandonment and reclamation."

Primary Barrier Envelope The first barrier envelope that prevents flow from a potential source of inflow (adapted from NORSOK Standard D-10).

Risk The combination of the probability of an event and its consequences (from *ISO/IEC Guide 73:2002* definition 3.1.1 "Risk management – Vocabulary – Guidelines for use in standards").

Safe Zone A designated area of low risk and minimal hazards that does not require special authorization to enter (e.g., muster point, first aid services, safety meeting area, office trailer).

Secondary Barrier Envelope A second barrier envelope is a barrier that is independent from the primary barrier envelope that prevents flow in the event the primary barrier fails (adapted from NORSOK Standard D-10).

Seismicity The occurrence or frequency of earthquakes in a region. There are several regulatory resources that discuss induced seismicity including

- AER (2015). Subsurface Order No. 2: Monitoring and Reporting of Seismicity in the Vicinity of Hydraulic Fracturing Operations in the Duvernay Zone, Fox Creek, Alberta
- BCER (2015). Defining: Induced Seismicity. The following studies are referenced in Defining: Induced Seismicity:
    - Investigation of Observed Seismicity in the Montney Trend (December 2014)
    - Investigation of Observed Seismicity in the Horn River Basin (August 2012)
- CAPP Hydraulic Fracturing Operating Practice: Anomalous Induced Seismicity: Assessment, Monitoring, Mitigation and Response.

Silica Exposure Area is an area surrounding the sand equipment present causing an elevated probability of silica dust exposure. This area is subject to change due to factors including weather, equipment (e.g., air can, sand conveyor), and active operations versus non-active operations.

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Simultaneous Operations Any operation not associated with the current fracture stimulation operation and occurring in close proximity to the subject well.

Special Consideration Well (SCW) Offset Wells proximal to the subject well beyond the FPZ that may have characteristics of unique concern which justifies further scrutiny.

Stress Anisotropy A condition where the forces (in-situ stresses) acting on rock are stronger in some directions than in others. This occurs naturally in rock formations and can influence wellbore stability, fracture geometry in resource development.

Stress-Induced Anisotropy A condition where uneven stresses (stress anisotropy) change how the rock behaves around a borehole. Drilling, hydraulic fracturing pressures and reservoir depletion can alter stresses around the borehole and impact fracture geometry.

Subject Well A well planned for fracture stimulation.

Subject well integrity Prevention of the escape of fluids (i.e., liquids or gases) to subsurface formations or surface (see AER Directive 083: Hydraulic Fracturing – Subsurface Integrity).

Subject Well Operator A person or company that has control of or undertakes the day-to-day operations and activities of a facility, pipeline, or well, whether or not that person is also the Licensee for the facility, pipeline, or well (see AER Directive 056: Energy Development Applications and Schedules, Appendix 3).

Subject wellsite supervisor The person responsible for the overall fracture stimulation operation at the subject well and responsible for the execution of the IOW Well Control Plan.

Subsurface Unintended Flow A flow of wellbore fluids (oil, gas, water, or other substance) in the subsurface from one formation to another formation.

Surface Unintended Flow An unmanaged flow of wellbore fluids (oil, gas, water, or other substance) at the surface that can be controlled by existing wellhead and/or blowout prevention equipment.

Surface Operations All above ground activities that pertain to the fracture stimulation of the subject well.

Target Zone The zone of interest to receive fracture stimulation in the subject well.

Uncontrolled Well Event A scenario in a well that may be a subsurface unintended flow, surface unintended flow, or a blowout.

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Well Control is a set of techniques, equipment and procedures used to prevent the uncontrolled release of formation fluids.

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Appendix H: References and Resources

DACC References

Available from www.energysafetycanada.com

- IRP 01: Critical Sour Drilling
- IRP 02: Completing and Servicing Sour Wells
- IRP 04: Well Testing and Fluid Handling
- IRP 05: Minimum Wellhead Requirements
- IRP 07: Competencies for Critical Roles in Drilling and Completions
- IRP 08: Pumping of Flammable Fluids
- IRP 13: Wireline Operations
- IRP 20: Wellsite Design Spacing Requirements
- IRP 21: Coiled Tubing Operations
- IRP 24 Hazard Register
- IRP 25: Primary Cementing
- IRP 26: Wellbore Remediation
- IRP 29 Temporary Pipework, Securement, and Restraint

Local Jurisdictional Regulations and Information

Alberta

Available from www.aer.ca

- Directive 008 Surface Casing Depth Requirements
- Directive 009 Casing Cementing Minimum Requirements
- Directive 010 Minimum Casing Design Requirements
- Directive 013 Suspension Requirements of Wells
- Directive 020 Well Abandonment
- Directive 030 Digital Data Submission of the Annual Oilfield Waste Disposition Report

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- Directive 033 Well Servicing and Completion Operations – Interim Requirement Regarding the Potential for Explosive Mixtures and Ignition in Wells
- Directive 035 Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection
- Directive 037 Service Rig Inspection Manual
- Directive 038 Noise Control
- Directive 044 Requirements for Surveillance of Water Production in Hydrocarbon Wells Completed Above the Base of Groundwater Protection
- Directive 047 Waste Reporting Requirements for Oilfield Waste Management Facilities
- Directive 051 Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements
- Directive 055 Storage Requirements for the Upstream Petroleum Industry
- Directive 058 Oilfield Waste Management Requirements for the Upstream Petroleum Industry
- Directive 059 Well Drilling and Completion Data Filing Requirements
- Directive 060 Upstream Petroleum Industry Flaring, Incinerating, and Flaring
- Directive 071 Emergency Preparedness and Response
- Directive 077 Pipelines – Requirements and Reference Tools
- Directive 083 Hydraulic Fracturing – Subsurface Integrity
- Directive 087 Well Integrity Management

British Columbia

Available from www.gov.bc.ca:

- Worksafe BC: Guidelines Part 23: Restraint and Piping Systems
- Well Decommissioning Guidelines – Abandonment plugging, ground water protection
- Drilling and Production Regulation
    - Section 21 – Fracturing Operations
    - Section 22 – Hydraulic Isolation
    - Section 25 – Inactive or Suspended Wells
    - Section 41 – Venting and Fugitive Emissions, SCVF, Gas Migration
- Dormancy and Shutdown Regulation
    - Section 11 – Annual Work Plan

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  - Section 19 - Liability Reduction

- Water Sustainability Act - Section 56 – Decommissioning or deactivating well

Available from www.bc-er.ca:

- BCER (2015). Defining: Induced Seismicity
- BCER (2014). Investigation of Observed Seismicity in the Montney Trend
- BCER (2012). Investigation of Observed Seismicity in the Horn River Basin.
- BC Energy Resources Activities Act
- Oil and Gas Activity Operations Manual
  - Section 9.3 Well Suspension
  - Section 9.4 Suspended Well Reporting Requirements
  - Section 9.6.16 Inter-wellbore Communication

Manitoba

Available from www.gov.mb.ca:

- Drilling and Production Regulation, 1994

Saskatchewan

Available from www.saskatchewan.ca:

- Directive PNG005: Casing and Cementing Requirements
- Directive PNG008: Disposal and Injection Requirements
- Directive PNG013: Well Data Submission Requirements
- Directive PNG014: Incident Reporting Requirements
- Directive PNG015: Well Abandonment Requirements
- Directive PNG025: Financial Security Requirements
- Directive PNG048: Hydraulic Fracturing Requirements
- Directive S-01: Saskatchewan Upstream Petroleum Industry Storage Standards
- Guideline PNG026: Gas Migration
- Guideline PNG029: Annulus Test Reporting Requirements
- Oil and Gas Conservation Act, 0-2
- Oil and Gas Conservation Regulations, 2012, 0-2 Reg. 6
- SK-PNG 048 Hydraulic Fracturing Requirements

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- Saskatchewan Occupational Health and Safety Regulations, 1996

Other References and Resources

- API HF1: Well Construction
  http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/hydraulic-fracturing/api_hf1_hydraulic_fracturing_operations
- API HF2: Water Management
  http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/hydraulic-fracturing/api_hf2_water_management
- API HF3: Practices for Mitigating Surface Impacts
  http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/hydraulic-fracturing/api_hf3_practices_for_mitigating_surface
- API 5CT: Specification for Casing and Tubing
  https://www.api.org/products-and-services/standards/important-standards-announcements/standard-5ct
- API TR 5C2: Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing, First Edition
  http://www.api.org/~/media/files/publications/addenda-and-errata/5c3%20addendum.pdf?la=en
- ANSI/NACE-MR0175-2021/ISO 15160:2020 Petroleum and Natural Gas Industries-Materials for Use in H_2S-Containing Environments in Oil and Gas Production. 2022. Houston, TX, USA: Association for Materials Protection and Performance (AMPP) and Vernier, Geneva, Switzerland: International Organization for Standardization (ISO).
- Canadian Society of Unconventional Resources
  http://www.csur.com/resources
- CAPP: Guiding Principles and Operating Practices for Hydraulic Fracturing
  http://www.capp.ca/getdoc.aspx?DocId=218125
- CAPP Hydraulic Fracturing Operating Practice: Anomalous Induced Seismicity: Assessment, Monitoring, Mitigation and Response
  http://www.capp.ca/publications-and-statistics/publications/217532
- DNV RP U301, Risk Management of Shale Gas Developments and Operations
  http://www.dnvgl.com/rules-standards/
- Energy Workforce and Technology Council, Well Stimulation Industry Guidelines March 2023
- Fracfocus.org Publications includes George King's SPE paper *Hydraulic Fracturing 101* (SPE 152596)
  http://fracfocus.org/publications
- Fracopedia
  http://www.oilandgasinfo.ca/fracopedia/
- NORSOK D-10: Well integrity in drilling and well operations
  https://www.standard.no/en/sectors/energi-og-klima/petroleum/norsok-standard-categories/d-drilling/d-0104/
- Orphan Well Association (www.orphanwell.ca)

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- PSAC Working Energy Code of Conduct
  http://www.oilandgasinfo.ca/working-energy-commitment/
- The Modern Practices of Hydraulic Fracturing: A Focus on Canadian Resources
  http://www.ptac.org/projects/142
- Worksafe BC: Guidelines Part 23: Restraint and Piping Systems
- United Kingdom HSE (Health Safety Environment) website for an industry guide
  https://www.hse.gov.uk/managing/theory/alarpglance.htm

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