

Change #	Section	Page #	Importance (H/M/L)	Statement in Question	Suggested Revision	Rationale	Notes	How it was Addressed	Resolved/Unresolved
1	24.3.2.3	11	H	Please be descriptive Shallow well Fracture Stimulation	Please be descriptive Distinguish between shallow well fracture stimulation (Hz wells) and sweet shallow natural gas fracture stimulation (vertical/directional, 600m TD). An exemption needs to be included for sweet shallow gas fracture stimulations.	Please be descriptive In southern Alberta 1000's of sweet natural gas fracture operations were conducted and there has been no fluid release to surface, contamination of non-saline aquifers, or breaches leading to loss of reserves. in some areas, 16+ wells per section. Once upon a time, the Milk River zone (~300mKB) was fractured with 30-50T per interval (3-7 intervals), without incident. Nowadays, the tonnage is more like 5-7T.	The extra costs associated within the IRP creates an uneconomical world in sweet shallow gas optimization projects.	The group noted that this comment was made regarding section 24.3.2.3 Shallow Well Fracture Stimulation. In this section the IRP states, "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." Given the IRP is simply requiring users to follow applicable regulations, no exemption can or should be made. Overall, the group agreed an exemption was not valid given the content in this section requires you to follow legislative requirements. No	Resolved
2	24.6 & 24.7.1.2	24	H	Interwellbore Communication Assessment and Identify Simultaneous Operations	An exemption needs to be included for sweet natural gas fracturing operations.	During sweet shallow gas fracturing operations, there has not been an incident of interwellbore communication. For the 1000's of wellbores fractured in Southern Alberta, the distance between wells is significant that during fracturing operations, offset wells are being logged, perforated or cleaned out with no indications of interwellbore communication. Also, breakdown and treating pressures + proppant volume are significantly lower when comparing to HZ or deep vertical fracture operations.	The extra costs associated within the IRP creates an uneconomical world in sweet shallow gas optimization projects.	The group disagreed with this request since it is important to assess the potential for interwellbore communication for any fracture operation. Section 24.6 Interwellbore Communication Assessment outlines this assessment process, identifies interwellbore communication as a risk that can result in a well control event, and indicates two means for minimizing this risk. It does not stipulate that fracture modelling is required for every well. No changes were made.	Resolved
3	24.6.1	H	H	Determine Fracture Geometry	An exemption needs to be included for sweet shallow natural gas fracturing operations.	Data to determine is limited or not available. For example, open hole log waivers were approved by the AER so all sweet shallow natural gas wells do not have the information required to fulfil a confident fracture stimulation program. Resulting in a non-confident fracture half length leading to a less than adequate FPZ.	The extra costs associated within the IRP creates an uneconomical world in sweet shallow gas optimization projects.	the commenter seems to have interpreted the IRP as requiring a fracture model for every fracture. However, this is not the case. The IRP provides two methods for determining fracture	Resolved

4	24.2.1	M	M	Fracture Stimulation A stimulation treatment involving specially engineered fluids that are pumped at a high pressure and rate into the reservoir causing a fracture(s) to open.	Re-evaluate this definition	There are two definitions for fracture stimulation. This one and the following: 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).	The committee replaced the definition with one aligned with the IRP Master glossary and the oilfield glossary: "A treatment performed above the fracture pressure of the reservoir formation to create a highly conductive flow path between the reservoir and the wellbore."	Resolved
5	24.2.1	M	M	Seismicity The occurrence or frequency of earthquakes in a region. There are several regulatory resources that discuss induced seismicity such as •NER (2015). Subsurface Order No. 2: Monitoring and Reporting of Seismicity in the Vicinity of Hydraulic Fracturing Operations in the Duvernay Zone, Fox Creek, Alberta •NER subsurface orders 6 and 7 •Alberta Geological Survey Alberta Earthquake dashboard •CER (2015). Defining: Induced Seismicity. The following studies are referenced in Defining: Induced Seismicity: oInvestigation of Observed Seismicity in the Montney Trend (December 2014) oInvestigation of Observed Seismicity in the Horn River Basin (August 2012) •British Columbia Smart Infrastructure Monitoring System •APP Hydraulic Fracturing Operating Practice: Anomalous Induced Seismicity: Assessment, Monitoring, Mitigation and Response •Natural Resources Canada Risk Profiler	Re-evaluate; listing resources associated with induced seismicity should not be included in a definition of seismicity.	There are two definitions of seismicity in the master glossary - they're the same except one includes the list of resources.	The committee removed the definition of seismicity since the IRP mainly focuses on induced seismicity. The committee added the following definition of 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. The references related to induced seismicity are referenced in appendix H.	Resolved
6	24.3	M	M	The equilibrium point in that balance is ALARP. For more information about ALARP see the UK HSE document, ALARP at a Glance, available from the UK Government Website (see Appendix H References and Resources).	No Canadian references?	In Canada, the ALARP (As Low As Reasonably Practicable) principle is widely used in high-hazard industries to meet the regulatory requirement of taking "all reasonable precautions." While not always explicitly named in federal acts, it is a foundational benchmark in several sectors: 1. Energy and Offshore Petroleum Canada Energy Regulator (CER): The CER references ALARP in its Safety Plan Guidelines, noting that while the specific term may not appear in the Canada Oil and Gas Operations Act, operators are expected to demonstrate that risks have been reduced to ALARP levels. Offshore Petroleum Boards: Both the C-NLOPB (Newfoundland and Labrador) and CNSOPB (Nova Scotia) utilize ALARP to evaluate safety plans for offshore drilling installations. 2. Nuclear Industry (ALARA) Canadian Nuclear Safety Commission (CNSC): In the nuclear sector, the related principle ALARA (As Low As Reasonably Achievable) is the legal standard. The Radiation Protection Regulations require licensees to implement a program to keep the amount of exposure to radon and other radiation "as low as reasonably achievable,"	The committee replaced the UK reference with the following: CER Safety Plan Guidelines, ISO 31000 Risk Management Guidelines, and CSA Z1002 Occupational Health and Safety Hazard Identification and Risk Assessment and Control (see Appendix H References and Resources).	Resolved

7	24.3	M	M	Figure 1 (all and all other figures)	Should this not be a link back to the management process?	Figure 1 and related FSHMP figures were updated to include arrows that point back to the beginning of the process (from change management to FSHMP). An arrow was added from continuous learning to change management.	Resolved
8	24.3.2.3	M	M	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.	What is 'near'? Suggest removing 'near the top of bedrock' and clarifying.	The committee did not agree with this suggestion. "Near" is relative depending on the size of fracture you're doing and therefore cannot be specified. The bedrock needs to be referenced. Since this is an awareness statement and not a definitive specification, the group did not feel a change was necessary.	Resolved
9	24.3.2.4	M	M	Induced seismicity (IS) is a seismic event resulting from human activity and can be caused by industries such as mining, dam impoundment, CO2 sequestration, geothermal activities, and hydrocarbon development (e.g., hydraulic fracturing, waste disposal or pressure maintenance, and extraction compaction ).	not sure this is the correct terminology. May want to just say from production and loss of volumetrics	The committee replaced 'extraction compaction' with 'subsidence'.	Resolved
10	24.3.2.4	M	M	• Identification of faults from available published data or 3D seismic reviews	Faults to what depth? Suggest removing 3D and just use seismic.	The group did not feel a major change was required and did not want to impose depth limitations. As the section provides examples of tools that may be used, the wording was revised to, "Identification of faults from available published data and/or seismic reviews."	Resolved

11	24.3.2.4	M	M	IRP Subject well operators shall complete a post-fracturing induced seismicity assessment to capture and share lessons learned from induced seismicity patterns and attributes.	Replace Shall with may and suggest removing 'share lessons...':		Given that BCER requires completion of post-fracturing induced seismicity assessments, and recognizing that additional regulators may adopt similar requirements in the future, the committee revised the statement to, "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."	Resolved
12	24.4	M	M	well control' (IOW Well Control Plan) and how this term is used throughout the IRP.	Well control is defined as managing pressure from the wellbore from uncontrolled flow - don't believe this is the right term to use here and throughout the IRP.	We may want to use well communication control. May want to use well communication event rather than well control event.	The committee clarified that well control refers to maintaining control of a well under pressure, not an uncontrolled condition. The following definitions were added or revised: Well Control "a set of techniques, equipment and procedures used to prevent the uncontrolled release of formation fluids" Uncontrolled Well Event which is "A scenario in a well that may be a subsurface unintended flow, surface unintended flow, or a blowout. "	Resolved
13	24.4	M	M	Surface Operations Change Management	Can the committee define or describe surface operations?		Surface operations is already defined in the glossary.	Resolved.

14	24.5.2.4	M	M	<p>Barrier envelope limitations may include, but not be limited to, the following:</p> <ul style="list-style-type: none"> <li>•Expected pumping pressures greater than the barrier envelope AMP</li> <li>•Potential failure modes (see 24.5.2.2 Identify Fracture Stimulation Factors )</li> </ul>	Should emergency shut down be included here?	<p>The group discussed this comment at length. Upon looking through the IRP, they discovered that emergency response is only addressed in terms of an offset well; this is in 24.6 "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." Under 24.5.3 They added the following statement "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."</p>	<p>Since emergency shut down is a remedy rather than a failure mode, the group did not add emergency shut down in the list of bullets. Instead they added the following under 24.5.3 "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." During discussion it was noted that the AER has seen changes in fracture operations that did not consider whether the casing design would be sufficient which resulted in significant damage to</p> <p>Upon discussion the group agreed that the parameters indicating an uncontrolled well event or communication are subjective depending on the well and the operation, and are identified in the Well Control Plan. They removed "or communication" from the two middle IRP statements and added "in accordance with the Well Control Plan" to the third statement.</p>	Resolved
15	24.6	M	M	<p>IRP if a well control event or communication to an identified offset well (IOW) occurs, the subject well operator must comply with local jurisdictional regulations.</p>	<p>when should they notify the operator and at what severity and fequency. Also suggest removing event and just saying well communicatoin.</p>			Resolved.

16	24.6	M	M	IRP If a well control event or communication to an IOW occurs, the subject well operator shall notify the IOW operator.	or reverse depending on monetary means	The group agreed that the onus should always be on the Subject Well Operator to notify the IOW operator when and uncontrolled well event occurs. Although the IOW Operator could notify the Subject Well Operator if they notice evidence of an uncontrolled well event the committee did not feel it was necessary to recommend this action. They revised the IRP statement to say "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."	Resolved.
17	24.6.1	M	M	<ul style="list-style-type: none"> <li>• <del>O</del>ther data sources</li> <li>o <del>T</del>racer data</li> <li>o <del>M</del>icroseismic data</li> <li>o <del>G</del>eological data (e.g., fault mapping)</li> <li>o <del>D</del>ata shared by other operators or service companies active in the area</li> </ul>	Suggest including plug slips or isolation and depletion for other data sources.	The committee added the following: <ul style="list-style-type: none"> <li>• <del>R</del>ecent reservoir pressure data (e.g., depletion, secondary recovery methods)</li> <li>• <del>I</del>solation failures causing fracture reactivation (e.g., plug slips).</li> </ul>	Resolved
18	24.6.2.4	M	M	Offset wells beyond the FPZ may be classified as SCWs if they meet some or all the following criteria: <ul style="list-style-type: none"> <li>• <del>H</del>istorical experience indicating elevated risk</li> <li>• <del>E</del>stimation uncertainty when determining the FPZ (see Appendix E Modeling Fracture Half-Length and Fracture Height)</li> <li>• <del>F</del>racture azimuth (consider surface and subsurface monitoring data, such as microseismic)</li> <li>• <del>G</del>eology (e.g., regions prone to natural faults and fractures)</li> <li>• <del>A</del>ge and condition of the offset wellbore</li> <li>• <del>F</del>reshwater or non-saline well</li> <li>• <del>S</del>aline water source well</li> <li>• <del>P</del>otential for pressure communication</li> <li>• <del>M</del>Wells with fracture half-lengths that may intersect the FPZ</li> <li>• <del>M</del>Wells being drilled with planned trajectories that intersect the FPZ (not necessarily during fracture operations)</li> <li>• <del>S</del>altwater disposal (SWD) well</li> <li>• <del>W</del>ater injection well (WIW)</li> <li>• <del>M</del>ineshaft, cave, non-energy wellbore</li> <li>• <del>O</del>perators requesting notification of nearby fracturing activities</li> <li>• <del>O</del>ther horizons with potential to be fractured into</li> </ul>	Also include acid gas injection, depletion, and gas storage.	The committee revised the list to include the following: <ul style="list-style-type: none"> <li>- <del>R</del>eservoir conditions (e.g., depletion, overpressure)</li> <li>- <del>D</del>isposal Well (e.g., salt water, acid gas, water injection)</li> <li>- <del>G</del>eothermal</li> <li>- <del>C</del>arbon capture utilization and storage (CCUS)</li> <li>- <del>B</del>rine-hosted minerals</li> <li>- <del>G</del>as storage</li> </ul>	Resolved

19	24.6.3.1	M	M	<p>• 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 <math>z_f</math> (whichever is greater), are classified as at-risk,</p>	<p>What is top of zone, what is a zone - how do we define this? Also what happens if you don't have 2D and 3D? What is the recommended practice?</p>		<p>The committee verified that zone is defined in the glossary and noted that this bullet identifies how to make a 2D and 3D when the data is not available.</p>	Resolved
20	24.6.3.1	M	M	<p>barrier envelope'</p>	<p>Barrier envelope and definitions don't align with fracture stimulation - they align more with well control.</p>		<p>The committee agreed and felt this alignment was correct in this context. The committee asked for further clarification in case they didn't understand the comment's concern; Ginette will follow-up with Adrian for clarification. Upon follow up, Adrian said that he'll leave it to the committee.</p>	Resolved
21	24.6.3.2	M	M	<p>Figure 11 Example Target to Target Flow Path Illustration</p>	<p>Label 'x' and include groundwater.</p>		<p>The commenter requested 'X' and groundwater be identified in Figure 11. Although the committee did not feel these additions were crucial to understanding the figure, they decided to add these. Steele will provide the updated figure before the next meeting. Upon review of the updated figure, the committee agreed labelling "x" was unnecessary, as it is commonly understood in industry to represent a valve. No further changes were made.</p>	Resolved
22	24.6.3.3	M	M	<p>The closer an at-risk IOW is to a fracture initiation point, the greater the probability of interwellbore communication . The probability also increases if the IOW has a relatively low AMP.</p>	<p>This may not always be true.</p>		<p>The group disagreed and kept the statement as is.</p>	Resolved
23	24.6.3.5	M	M	<p>IRP Real-time pressure monitoring with alarms below the IOW's AMP should be considered as a risk mitigation measure.</p>	<p>what is real time - maybe state there needs to be a communication/notification system.</p>	<p>"real-time" means the continuous, immediate collection, processing, and analysis of data from sensors (like pressure, flow, temperature) typically a pressure transducer records 20 times per sec but standard industry records every sec.</p>	<p>The committee added "(i.e., instantaneous and continuous)" to clarify that real-time monitoring is instantaneous and continuous.</p>	Resolved

24	24.6.3.5	M	M	IRP The subject well operator shall incorporate the IRP 24 Hazard Register, or equivalent known hazard scenarios, into risk assessment processes to identify additional considerations .	state this needs to be documented per company or regulatory requirements	The committee revised the IRP statement to "The subject well operator shall incorporate the IRP 24 Hazard Register or equivalent known hazard scenarios, into documented risk assessment processes."	Resolved
25	24.6.4.1	M	M	<ul style="list-style-type: none"> <li>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: <ul style="list-style-type: none"> <li>lowest adjusted maximum pressure on the flow path</li> <li>reservoir and/or fracture stimulation fluid type (e.g., gas or liquid, sweet or sour)</li> <li>maximum potential flow rate from the at-risk IOW</li> <li>fluid volume</li> </ul> </li> </ul> IRP 04: Well Testing and Fluid Handling	may want to remove IRP 4 as it may not fit well here or remove as a bullet point.	Reference to IRP 24 was removed from the bulleted list. Instead there is now a statement saying "see IRP 4".	Resolved.
26	24.6.5	M	M	Note: For orphan wells, the IOW operator is the local jurisdictional regulator and/or local orphan well association.	Should we include anything on drone footage, INSAR, satellite, methane detection with drons, etc.	The group added drones and satellite as examples under 24.6.4.1 Identify IOW Well Control Practices. They declined to recommend methane detection.	Resolved
27	24.6.5	M	M	<ul style="list-style-type: none"> <li>Establish field -level communication contacts between the subject well and IOW operators for pre-, during, and post-fracture stimulation notifications,</li> </ul>	may want to state have emergency protocols in place.	The committee incorporated this suggestion into the following bullet: "Engage in collaborative consultation to develop a mutually agreed-upon IOW Well Control Plan (including emergency protocols)."	Resolved
28	24.6.5	M	M	IRP The subject well operator should maintain records of communications with the IOW operator regarding the consultation process, including confirmation of the final IOW Well Control Plan.	and risk assessment? What duration?	The committee revised the IRP statement to read: "The subject well operator should maintain records of communications with the IPW operator regarding the consultation process, including risk assessment and confirmation of the final IPW Well Control Plan."	Resolved
29	24.6.5	M	M	IRP The IOW operator shall, at a minimum <ul style="list-style-type: none"> <li>Develop an internal process to review and respond to subject well operator requests ,</li> </ul>	suggests meeting jurisdictional standards and regulation	The committee noted that no regulations require IOW operators to establish such an internal process. As a result, no change was made.	Resolved

30	24.7 M	M	If hazards are reduced to an acceptable level, fracture stimulation can proceed. If not, the changes need to be managed (see 24.4 Change Management).	who deems acceptable - clarify thiwho does this	The committee discussed that acceptable risk is company-specific and depends on the operators risk tolerance and hazard management processes. To clarify this, the statement was revised to, "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."	Resolved
31	24.7 M	M	The surface operations hazard assessment begins at the fracture iron , where subject well integrity assessment ends. This stage identifies surface areas, assesses hazards, and addresses hazard management planning and wellsite execution.	Where does the fracture iron start - the wellhead?	To improve clarity, the committee revised the statement to indicate that the surface operations hazard assessment includes all above-ground equipment and activities except the wellhead equipment. The committee revised the statement to the following, "The surface operations hazard assessment includes all above-ground equipment and activities except the wellhead equipment (see 24.5 Subject Well Integrity Assessment)"	Resolved
32	24.7 M	M	Fracture stimulation is a complex operation. Multi-well leases may increase activity and congestion, often under erosive, 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.	suggest removing erosive	The committee revised the statement to the following, "Fracture stimulation is a complex operation. Multi-well leases may increase activity and congestion, often under when pumping erosive fluids under high-pressure conditions."	Resolved

33	24.7	M	M	IRP If an incident occurs at the wellsite during fracture stimulation operations, the subject well operator's Emergency Response Plan (ERP) must be invoked in accordance with local jurisdictional regulations.	What is an incident?	May want to say 'emergency incident'.	During discussion, the committee noted that the statement was ambiguous and not always accurate, as ERPs are not necessarily invoked for all incidents. The statement was revised to, "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."	Resolved
34	24.7.1	M	M	IRP The subject well operator, in consultation with the service company or companies, shall determine relevant safe areas, hazard areas, simultaneous operations areas, and special consideration locations for the fracture stimulation operation.	should we say risk assessment which is required by OHS		The committee agreed that Occupational Health and Safety regulations require risk assessment and revised the statement to include this requirement, stating that the operator shall conduct a surface hazard assessment to determine these areas. The committee revised the statement to the following, "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."	Resolved

35	24.7.1	M	M	Figure 14 Lease Map Showing Safe Area and Hazard Areas	Don't like this drawing. Suggest it be updated.	<p>Note: this drawing was from IRP 29. Kolton conversed with Adrian and clarified that Adrian wanted a more updated version of the illustration showing modern-day operations involving multi-well pads and additional operations. Kolton will work with Matt to provide an updated drawing.</p> <p>These comments were discussed at a previous meeting. Updated versions of figures 14 and 15 were presented. The committee supported the updates and recommended the following improvements:</p> <ul style="list-style-type: none"> <li>• Label hazard areas directly on the figures rather than using a separate legend</li> <li>• Replace light yellow shading with a more visible colour for the silica exposure zone</li> <li>• Identify the location of the data van</li> <li>• Add acid tanks.</li> </ul> <p>Kolton and Matt will incorporate these updates, and Ginette will insert the revised figures into the IRP.</p>	The illustrations were updated to better reflect modern-day operations.	Resolved
36	24.7.1.1	M	M	Determine Safe Area	May want to include muster practice, etc. requirements		The committee noted that muster practices are not standardized across operations and determined that it was not necessary to specify muster practices within this section.	Resolved
37	24.7.1.1	M	M	IRP Entry into an exclusion zone shall be avoided except for short-duration tasks. Where entry is necessary, the subject well operator and service company or companies shall	What is short duration. Suggest not using a time frame.		<p>The committee agreed with the suggestion and changed the statement to the following, "Entry into an exclusion zone shall be avoided. When entry is necessary, the subject well operator and service company or companies shall</p> <ul style="list-style-type: none"> <li>• Have a formal approval process in place,</li> <li>• Minimize the number of workers entering the zone and the length of time they remain in the zone and</li> <li>• Ensure the approval process complies with site requirements, operator procedures, and applicable jurisdictional regulations." </li></ul>	Resolved

38	234.7.1.1.3	M	M	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.	Reiterate in accordance with OHS and this is therefore a must		The committee agreed that hazards must be assessed and re-assessed under OHS regulations; however, the regulations do not specifically require the identification of elevated hazard zones in this context. Therefore, no change was made.	Resolved
39	24.7.1.1.4	M	M	The silica exposure area is the area surrounding the sand-handling equipment 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.	what is sand-handling - suggest areas where sand is open to the atmosphere where there could be exposure. Should also include silica must be measured in accordance with OHS requirements		The committee noted that silica exposure can occur even when sand is not open to the atmosphere. The statement was revised to, "The silica exposure area is where there is an elevated probability of silica dust exposure."	Resolved
40	24.7.1.2	M	M	Figure 15 Simultaneous Operations	suggests using a drone shot or include a better illustration of current operations.	Kolton will work with Matt to update the illustration to show a more modern SIMOPs. These comments were discussed at a previous meeting. Updated versions of figures 14 and 15 were presented. The committee supported the updates and recommended the following improvements: <ul style="list-style-type: none"> <li>•Label hazard areas directly on the figures rather than using a separate legend</li> <li>•Replace light yellow shading with a more visible colour for the silica exposure zone</li> <li>•Identify the location of the data van</li> <li>•Add acid tanks.</li> </ul> Kolton and Matt will incorporate these updates, and Ginette will insert the revised figures into the IRP.	The illustrations were updated to better reflect modern-day simultaneous operations.	Resolved.
41	24.7.1.3	M	M	Examples of off-lease surface risks include, but not be limited to the following: <ul style="list-style-type: none"> <li>•Extensions of fracture stimulation operations off-lease (e.g., overland pumping operations)</li> <li>•Proximity to public areas and residential locations</li> <li>•Road usage impacts</li> <li>•Offset wells identified in the IOW Risk Assessment</li> <li>•Environmentally sensitive areas and wildlife habitats</li> <li>•Existing infrastructure (e.g., power lines, pipelines)</li> </ul>	suggest stating an environmental assessment.		The committee noted that conducting an environmental assessment is a significant undertaking that would typically occur well before fracture operations. The example was revised to "known environmentally sensitive areas and wildlife habitats."	Resolved
42	24.7.2.1	M	M	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 <ul style="list-style-type: none"> <li>oErosion,</li> <li>oOver-pressuring,</li> <li>oChemical degradation and</li> <li>oStress fatigue.</li> </ul>	Is this the correct term or should it be incompatibility.		The committee noted that both incompatibility and degradation are potential hazards and changed the example to include both.	Resolved

43	24.7.2.3	M	M	IRP Liquids (e.g., water and/or hydrocarbons) and H2S shall be removed in all applications. Adequate detection methods shall be in place, and gas supply shall be isolated if either is detected.	it should be limited and removed according to regulations. All is not practicable.	The committee agreed that liquids are detrimental to equipment operation but cannot always be removed. They also determined that H2S was not relevant to the statement. The statement was revised to, "All liquids are detrimental to equipment operation. Liquids (e.g., water and/or hydrocarbons) shall be removed."	Resolved
44	24.7.2.3	M	M	IRP gas sample analysis shall be conducted before use to confirm gas quality.	A representative gas analysis shall be conducted. - state this rather than using a time frame.	The committee agreed and removed the phrase "before use".	Resolved
45	24.7.2.3	M	M	Process and Distribution Equipment	Should we say something about an ESD?	The committee agreed and revised the statement to include ESD valves, "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)."	Resolved
46	24.7.2.3.2	M	M	IRP electrical equipment shall be certified by a recognized agency .	Identify who this would be	The committee revised the statement to the following, "Electrical equipment shall be certified by an agency accredited by the Standards Council of Canada" in accordance with the Canadian Electrical Code.	Resolved
47	24.7.2.3	M	M	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.	Check if this is referenced in CEC.	The committee confirmed that it is not referenced; however, the CSA standard provides practical guidance for determining clearance distances between arc-producing equipment and combustible gas relief devices or vents. The reference was retained.	Resolved

47	24.7.2.3	M	M	IRP The subject well operator, in consultation with the service company or companies, shall determine adequate grounding resistance .	WorksafeBC has recommendations for this. We may want to reference their suggested resistance.	The committee noted that the previous statement already required electrical equipment to be properly grounded and bonded. As a result, the statement regarding grounding resistance determination was removed.	Resolved
48	24.7.3	M	M	IRP The subject well operator, in consultation with the service company or companies shall 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).	This may need to be a must	The commenter suggested that the IRP statement in 24.7.3 Create Surface Operations Hazard Management Plan, be written as a "must" statement. The committee agreed and revised the wording accordingly.	Resolved
49	24.7.3.3.1	M	M	IRP The subject well operator shall provide each service company or companies connecting to a well with, at minimum, the expected operating pressures, wellbore fluid composition, and maximum working pressures.	ould this be a must? Adrian says it is a must	The committee noted that the statement reflects best practice rather than a regulatory requirement and therefore the term "must" cannot be used.	Resolved.
50	24.8.1.1	M	M	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).	What is a pass for the pressure test. What is an acceptable duration for a pressure test.	The committee noted that the following statement already provides sufficient guidance and determined that no changes were necessary, " At a minimum, the system should hold the test pressure for as long as necessary to detect leaks and allow the pressure to stabilize."	Resolved
51	24.8.2	M	M	IRP The lines between the fracture pump and wellhead shall be pressure tested at 10% above anticipated service pressure, without exceeding the OEM-rated working pressure of the equipment. Refer to local jurisdictional regulations for specific requirements.	Is this a regulatory requirement	The committee confirmed that it is not a regulatory requirement. They also noted that the 10% value is not standardized. The statement was revised to remove the 10% reference and replace anticipated service pressure with maximum allowable operating pressure.	Resolved

52	24.6.2.2	M	M	Step 1. Using the longest xf determined, draw the FPZ outer boundary of to a distance equal to twice the fracture half-length (2xf) from the wellbore around the plan view of the well (see Figure 7).	There is mention on page 28 of using 2x XF for the FPZ. Should the 2x be an IRP statement as a starting point if your company doesnt have a standard.		The committee changed "Step 1" to an IRP statement and revised it to say "Using the longest xf determined, the Subject Well Operator shall draw the FPZ outer boundary of to a distance equal to twice the fracture half-length (2xf) from the wellbore around the plan view of the well (see Figure 7)."	Resolved
53	24.6.3.3	M	M	The probability also increases if the IOW has a relatively low AMP.	there should be a edit here as a LOW AMP does not increase probability, but it may increase severity or risk.		As the committee was discussing comment #22, they noted that the following statement, "The probability also increases if the IOW has a relatively low AMP" did not make sense and therefore removed it. Due to removing this statement comment #53 was resolved.	Resolved
54	24.7	M	M	The surface operations hazard assessment begins at the fracture iron , where subject well integrity assessment ends.	hazard assessment begins at the fracture iron' . I think this should state at the flange of the wellhead or frachead.		To improve clarity, the committee revised the statement to indicate that the surface operations hazard assessment includes all above-ground equipment and activities except the wellhead equipment.	Resolved
55	24.7.2	M	M	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).	should reference Figure 15, not 18.	Ginette will correct the figure numbering once all revisions are complete.		
56	24.7.2.3	M	M	IRP liquids (e.g., water and/or hydrocarbons) and H2S shall be removed in all applications. Adequate detection methods shall be in place, and gas supply shall be isolated if either is detected.	Gas Quality - liquids - hydrocarbons cannot always be removed, but they can be created if pressure and temperature of the gas source decrease. I think its relevant to include a mention of a phase envelop and ensuring the source gas remains in the gas phase.		The committee agreed that liquids are detrimental to equipment operation but cannot always be removed. They also determined that H2S was not relevant to the statement. The statement was revised to, "All liquids are detrimental to equipment operation. Liquids (e.g., water and/or hydrocarbons) shall be removed."	Resolved

57	24.7.2.4	M	M	<p>A review of relevant IRPs and guidelines may provide additional guidance. Examples may include the following :</p> <ul style="list-style-type: none"> <li>•IRP 04: Well Testing and Fluid Handling</li> <li>•IRP 05: Minimum Wellhead Requirements</li> <li>•IRP 07: Competencies for Critical Roles in Drilling and Completions</li> <li>•IRP 08: Pumping of Flammable Fluids</li> <li>•IRP 13: Wireline Operations</li> <li>•IRP 20: Wellsite Design Spacing Recommendations</li> <li>•IRP 21: Coiled Tubing Operations</li> <li>•IRP 29 Temporary Pipework, Securement, and Restraint</li> </ul>	IRP 6 and 7 can contradict each other. I think they can be merged or 7 can be deleted.		The committee clarified that IRP 06 has been retired and is not referenced in this section; therefore, no changes were required.	Resolved
58	Appendix D	M	M	<ul style="list-style-type: none"> <li>•Partial pressure (pp) H<sub>2</sub>S—influences barrier metallurgy requirements or performance</li> <li>o pp H<sub>2</sub>S &lt; 0.3 kPa (Minimum Safety Factor Burst = 1.10)</li> <li>o 0.3 ≤ pp H<sub>2</sub>S ≤ 10 kPa (Minimum Safety Factor Burst = 1.20)</li> <li>o pp H<sub>2</sub>S &gt; 10 kPa (Minimum Safety Factor Burst = 1.25)</li> </ul>	partial pressures and safety factors - there should be a reference for this parameters.	the H <sub>2</sub> S partial pressures identified in Appendix D, originated 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 <sub>2</sub> S-Containing Environments in Oil and Gas Production. The minimum safety factor of 1.10 for sweet service was established in API TR 5C3. AER Directive 10 established the additional minimum safety factors of 1.20 and 1.25 as regional requirements for higher-concentration sour environments. These references were added in Appendix D for clarification and to address comment #58	The committee confirmed that similar values are referenced in AER Directive 010 (section 1.8 Burst Design Factor Adjustments) but may originate from other sources such as NACE or API. It was also noted that Directive 010 references IRP 1. Ginette will review IRP 1 to confirm the original source.	Resolved.
59	Throughout		M	The figure flow chart colour choices are about the worst I have seen. White in light blue and soft grey in light grey (It couldn't have been black in light grey)?			The committee agreed to revise the formatting by changing the dark grey font to black and adjusting the light blue fill to a darker blue to improve contrast.	Resolved
60	Throughout		L	I know I run a bigger font size than you when I read, but I had to increase the magnification of the document so that the skinny lettering had better contrast for these old eyes. And then that didn't make looking at the Manual easier to follow.			The committee noted the IRPs use a standardized template and that no other feedback has been received regarding font readability. The committee determined that this may be an individual viewing issue. No change was made.	Resolved

61	24.5.2.1	20	M	<p>24.5.2.1 Analyze Subject Well Barrier Envelope</p> <p>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).</p> <p>IRP The subject well operator shall determine the subject well barrier envelope(s) AMP.</p> <p>IRP Subject well barrier envelope analysis should include the following steps:</p> <ul style="list-style-type: none"> <li>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).</li> <li>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 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.</li> <li>Tri-axial load modeling should be considered for initial casing design and when well design assumptions change</li> </ul>	<p>AMP methodology should define:</p> <ul style="list-style-type: none"> <li>Minimum burst and collapse safety factors</li> <li>Temperature derating requirements</li> <li>Sour service derating requirements</li> </ul>	<p>The document requires operators to determine a Barrier Envelope Adjusted Maximum Pressure (AMP) but:</p> <ul style="list-style-type: none"> <li>No standardized calculation method is defined.</li> <li>No minimum safety factors are prescribed.</li> <li>Adjustment is left to "operator discretion."</li> </ul> <p>Technical Concern: This introduces variability between operators and inconsistent engineering thresholds across assets.</p> <p>Risk:</p> <ul style="list-style-type: none"> <li>Inconsistent burst/collapse margins</li> <li>Potential underestimation of true casing limits</li> <li>Misalignment between operator and service company pressure constraints</li> </ul>	<p>The committee agreed that prescribing a standardized calculation with fixed safety factors is not practical due to the number of variables involved. The committee noted that relevant considerations are identified in Appendix D and added a reference to the appendix within the applicable IRP statement to improve visibility.</p>	Resolved
62	None	None	M	<p>Should there be a section on loss of containment and impacts to offsetting wells if there is potential H2S or CO2 contamination to reservoirs?</p>			<p>The committee discussed the suggestion and agreed that an additional section was not necessary, as the IRP already requires a risk assessment and well control plan to address these risks. No changes were made.</p>	Resolved
63	24.6.3.1	32	H	<p>A well is consider at risk if - in the absence of historical data, wells located within 200 m above the top or below the bottom of the target zone, or within 2xZf (whichever is greater) are classified as at - risk</p>	<p>Wondering where the 200 m depth came from? Agree with 2xZf, concerned that 200 m does not seem sufficient in the absence of historical data.</p>	<p>CNRL has documented cases of communications outside (~450 m above) the target horizon, specifically in Deep Basin, northern parts Suggest to contact directly (Mike Elliot, 403-202-9360, Mike.Elliot@cnrl.com) for more specific information</p>	<p>The committee confirmed that 200 m is intended as a guideline starting point and emphasized that the IRP specifies 200 m or two times Zf (whichever is greater). The committee agreed that this approach provides sufficient flexibility and no changes were made.</p>	Resolved

64	24.6.3.1	32	H	<p>Statement 1: Subject well shall identify at-risk IOWs from the complete set of IOWs as per Step 1</p> <p>Statement 2: 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.</p>	<p>Suggest to swap the order of these 2 statements and separate them (for example, add white space or a formatting box) for maximum impact / clarity.</p>	<p>During our group review we interpreted this section as suggesting that wells outside the Zf did not require notifications. Due to the large number of wells that CNRL owns, data integrity issues in Accumap and other platforms, and the use of 3rd-party companies (iFracture, Tronic, et al) to do FPZ assessment and notifications, a concern that this would result in under-identification of at-risk IOWs was raised. (Upon closer review, the IRP still recommends that ALL wells inside the 2 dimensional FPZ require owners to be notified, which CNRL is aligned with)</p> <p>Due to the large number of wells that CNRL owns, data integrity issues in Accumap and other platforms, and the use of 3rd-party companies (iFracture, Tronic, et al) to do FPZ assessment and notifications, a concern that this would result in under-identification of at-risk IOWs was raised.</p>	<p>The committee reversed the order of the statements as suggested.</p>	Resolved
65	24.3.2.4	12	L	<p>During fracture stimulation activities the subject well operator and service company or companies must follow local jurisdictional requirements for seismic monitoring</p>	<p>More of a clarification question but the change could be as simple as replacing "well operator and service company" with "well operator to ensure all local jurisdictional requirements for seismic monitoring are met for all operations."</p>	<p>This statement suggests that the operator and service company both need to have their own monitoring setup? Pacific Canbriam sets up Accelerometers and Seismometers that provides overlapping blanket coverage over our target and surrounding areas, following seismicity protocols outlined with BCER and local jurisdictional requirements. We also have engineers monitoring the area. Do service companies (like frac stimulation companies) need to have their own set up as well during operations?</p>	<p>The committee clarified that service companies are typically engaged by the subject well operators to perform seismic monitoring on their behalf. The IRP requires that all parties follow local jurisdictional requirements for seismic monitoring; it does not require duplicate systems. The committee agreed the current wording is appropriate and no changes were made.</p>	Resolved
66	24.6.5	37-38	H	<p>Each at-risk IOW shall have a well control plan developed collaboratively; limited practical guidance when an offset operator refuses mitigation or declines participation.</p>	<p>Add a decision framework / examples for scenarios where IOW operator refuses mitigation: acceptable alternate mitigations (design changes, monitoring, additional barriers), documentation expectations, and when regulator engagement is recommended.</p>	<p>Real-world situations include non-cooperation. Additional guidance reduces uncertainty, supports consistent ALARP decisions, and improves risk management defensibility. Suggest including a simple flowchart (engage → document → alternate controls → escalate) within IOW consultation section.</p>	<p>The committee noted that existing guidance includes documentation of communications with IOW operators and emphasized that cooperation cannot be enforced. The committee agreed that the current guidance is sufficient and no changes were made.</p>	Resolved

67	24.7.3.3	52 M	Iron management replaced by Pipework Management System aligned with IRP 29; operators and service companies have roles in securement, documentation, and records.	Clarify minimum operator verification expectations versus service-company records retention (e.g., what must be reviewed onsite vs. retained in files) and provide a minimum documentation checklist aligned to IRP 29.	Reduces duplication and ambiguity between operator and service provider responsibilities; improves practical implementation and auditing. Checklist could include tracking IDs, cert/recert, inspection intervals, pressure ratings, restraint/securement, PFD/P&ID for temporary pipe.	The committee revised the wording in section 24.7.3.3 to refrain from duplicating content from IRP 29.	The committee reworded this section to prevent duplication with IRP 29. The verification statement was updated to read "The Subject Well Operator, in consultation with the Service Company or Companies, shall verify that a pipework management system is in place." The committee agreed that additional detail regarding verification was not necessary, as implementation is the responsibility of the operator and service companies. The committee also agreed that a checklist was not necessary.	Resolved
68	24.5.2.3 (I think they meant 24.5.2.1)	19 L	Tri-axial load modeling referenced as an engineering consideration for barrier envelope analysis and when assumptions change.	Explicitly state tri-axial modeling is risk-based and not required for all wells; include example triggers (high treating pressure vs ratings, fault proximity, deformation history, high DLS, shallow/sensitive zones).	Prevents misinterpretation as a universal requirement; supports proportional engineering effort aligned with ALARP. Could be a short note in SWI section plus example triggers in an appendix.		The committee noted that the IRP states tri-axial load modelling "should be considered," which indicates it is not mandatory. The committee agreed that the wording is clear and no changes were made.	Resolved