ERCB Energy Resources Conservation Board

Directive 083: Hydraulic Fracturing – Subsurface Integrity Stakeholder Feedback and ERCB Responses

Section numbers referenced in the "ERCB Response" column refer to the May 2013 version of the directive. The "Stakeholder Feedback / Issue" column has not been edited.

Stakeholder Feedback / Issue	Stakeholder	ERCB Response
1. Air Quality		
Consider including air pollution caused by surface activities around well pads (e.g. diesel trucks hauling fracture fluids). Lack of air quality management in the directive and/or linkage to directives which speak to air quality.	Public / Alberta Health	The setting of air quality standards is not within the jurisdiction of the ERCB. *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* regulates the management of emissions from oil and gas activities.
When policy is created about air quality and seismic concerns, the directive will need to be re-examined.	Alberta Health	As new policies are created all affected directives will need to be re-examined.
2. Base of Groundwater Protection (BGWP)		
How is the fracture exclusion zone of 100 metres below the depth of an adjacent water well in Section 5.3 consistent with the agreements between ERCB/ESRD as stated in Section 3, 3(i)(ii) of *Bulletin 2010-17: Clarification to the "Memorandum of Understanding Between the Alberta Energy and Utilities Board and the Alberta Environment Regarding Subsurface Waste Disposal Applications"* regarding the BGWP and injection fracture formation requirements? How is the same requirement consistent with the 25 metre requirement below the BGWP imposed for deep wells?	Public	*Bulletin 2010-17* regulates selection of an injection formation for oilfield waste (may contain environmentally deleterious substances). The hydraulic fracturing directive prohibits the use of fluids that may cause adverse effects to the nonsaline aquifers if there is a potential for the hydraulically induced fractures to propagate above the BGWP. The exclusion zone only pertains to the water wells. The nonsaline aquifer protection requirements are mitigation measures and provide additional protection to the water wells.
Section 2.3.3(4)(c): How will existing monobore wells with surface casing set above the BGWP be handled (i.e., grandfathered)? Section 4: Why nonsaline aquifer protection and not groundwater protection? The concern in this section seems to be talking about groundwater protection used for human consumption and agricultural use. Section 4.3.2(15): Either discuss nonsaline aquifers in general or exclusively groundwater protection. The distinction needs to be made to clarify interpretations in this requirement. Looks like the lettered items in 4.3.2(15) are a repeat of 3.3.2(8). Needs a thorough technical edit from the perspective of shallow operations and how they relate to aquifers. Suggestion to rewrite the section with a clear focus on the protection of groundwater and pertinent to shallow fracture operations.	Industry	Section 2.3.3 of the directive has been revised to address existing monobore wells with surface casing set above the BGWP. BGWP includes all aquifers with nonsaline groundwater as defined by the *Water Act* for potential future use. Section 4.3.2 of the directive has been reworded for clarification. Additional definitions were also added to the directive.

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3. Chemicals in fracture fluids		
How will the ERCB be able to determine the impact of the chemicals used in fracture fluids?	Public	A requirement was added in section 4.3.2 of the directive to address these concerns.
Disclosure of chemicals being used.		*Directive 059: Well Drilling and Completion Data Filing Requirements* and the FracFocus Chemical Disclosure Registry (found at www.fracfocus.ca) address these concerns.
What are the criteria for toxicity of chemical additives?		Added additional requirements regarding when the use of fracture fluids that will not cause an adverse effect on nonsaline aquifers are required. *Directive 059* also provides criteria for chemicals.
General concerns were raised regarding fracturing - mostly focused on chemicals in hydraulic fracturing fluid.		This is covered in *Directive 059*.
4. Clarification		
Section 1.3: Clarify the term "vertical setback". Identification of "bedrock" may be nebulous.	Industry	Changed the term "vertical setback" to "vertical restriction." Included bedrock in the definitions.
Section 2: Clarify this section deals only with subject wells that are to be hydraulically fractured.		Changed the title to clarify that this section deals only with subject wells.
Section 2.3.1: The term "dual-barrier" has different definitions and requirements and must be defined clearly. The directive says the dual-barrier is required to be in place to "operate the well". Does this apply to production operations? Would the dual-barrier requirement stay in place indefinitely, or only apply during the fracture treatment? The requirement to have a single-barrier system to provide a level of well integrity that is equivalent to a dual-barrier system is concerning. As written it indicates that "monobore" completions are not allowed under any circumstance.		Revised all of section 2.3 for better clarity and added the following definitions: - dual-barrier system - single-barrier system - primary barrier - secondary barrier
Section 2.3.2: There were questions regarding clarity to the configuration of the dual barrier system and to the expectation of using this system. There were concerns regarding cement not being considered as a barrier for hydraulic fracturing operations when it is considered a barrier in other directives (i.e. D 020, D 008, D 009, etc.).		Revised section 2.3.2 to indicate the components of a dual barrier system (with a simplified diagram). Cement is not considered a barrier with regards to hydraulic fracturing due to the high pressures the cement will be exposed to; this may impact the ability to isolate the formation.
Section 2.3.3: There were concerns regarding cement not being considered as a barrier for hydraulic fracturing operations when surface casing is set above the BGWP Need more clarity in the documentation requirements for this section.		Single-barrier and cement does not act as a dual-barrier design. The pressures the cement will be exposed to may impact the ability to isolate the formation. Revised section 2.3.3 to include what information must be documented.

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Section 2.3.3(4)(e): More detail or clarity is requested for this section.		Revised section 2.3.3 for better clarity.
Section 3.3.2: The definition of offset wells includes abandoned wells, for which the operator may be defunct. The ERCB may want to include a "reasonable efforts" statement to deal with this situation.		A requirement was added in section 3.3.4 to identify how licensees should address an offset well that does not have an active licensee.
Section 3.3.2: What do you mean by response plan: site-specific ERP or well control plan for at-risk offset wells? Is this meant to encompass events occurring beyond offset wells identified as at-risk?		Removed the term "response plan." Created section 3.3.3, At-risk Offset Well Control Plans, to better define the requirements.
Section 3.3.4: Would a licensee of a subject well be held accountable for a loss of well control on an offset well if the offset well licensee had been properly informed? Would prefer additional clarity be added to the above statement whereby responsibility for well control is dependent on the licensee of the well provided accurate stimulation data was provided.		Licensees are responsible for maintaining control of their wells.
Section 4: Recent regulatory decisions have differentiated between potable water in use and nonsaline ground water. Clarification may be beneficial.		All nonsaline aquifers above the BGWP are considered.
Section 4.3.1(12): Define the word "impact". Is it the same definition as in EPEA?		Reworded the directive to use the term "adverse effect" (where appropriate) and defined to be consistent with the *Environmental Protection and Enhancement Act (EPEA)*.
Section 4.3.2 Is there criteria/definition for nonsaline aquifers that have not been tested for TDS? Directive 020 defines "protected intervals" - are these considered nonsaline aquifers?		Definitions of a nonsaline aquifer and the BGWP are added. In general, any aquifer above the BGWP should be considered nonsaline unless a representative sample of groundwater with the TDS in excess of 4000 mg/L was obtained.
Section 5: Clarify whether the proposed setbacks are for the wellbore itself or for the associated fractures.		Revised wording in section 5.3 to clarify that a company cannot initiate fracturing operations within the restrictions.
Section 5.3: a) Clarification on wording. Clarify that the draft directive also means water well-to-subject well offsets.		Revised figure 1 for clarity.
Section 6: a) There is no longer a depth constraint from ground level. Is that correct?		*Directive 027: Shallow Fracturing Operation – Restricted Operations* did not have a depth constraint from ground level. The depth constraint was from the top of the bedrock surface.

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Section 7: Are these the only requirements that apply to nitrogen fracturing operations or are they in addition to all the requirements of this directive but with changes to the water well and bedrock setbacks?		Section 7 of the directive outlines requirements that have special provisions specific to the use of nitrogen as the fracturing fluid for coalbed methane completions. All requirements of this directive apply; however, if using nitrogen as the fracturing fluid for coalbed methane completion, then the water well and bedrock depth provisions apply.
Section 7.1: Lack of definition on whether a fracture initiation or a fracture extension is planned into the 200 metre radius.		Reworded section 7.1 for clarity.
Section 7.3: The 15,000 cubic metre volume seems to prescriptive. Isn't there a possibility that an operator could pump more with success while still complying with directive requirements? Does this apply to only shallow CBM (rather than Manville CBM)?		This requirement has not changed from the existing *Directive 027*.
Section 8: Please clarify: If an operator fractures into another well belonging to itself and in the same producing formation, does the ERCB expect to be notified? As stated previously, in some cases communication is intended (or expected).		The ERCB is to be notified of any communication with an offset well, regardless of the location or operator of the offset well.
Section 12: Definition of "Threshold Pressure" is not consistent with IRP 24 which has changed this definition to "Adjusted Maximum Pressure".		Made definition consistent with IRP 24. Added additional definitions to the directive for added clarity.
5. Coalbed methane nitrogen fracturing		
Licensee commented that fracturing into CBM zones should be its own directive.	Industry	The ERCB has chosen not to create a different directive for CBM fracturing.
Section 4.3.2: Outlines a stringent set of rules regarding risk assessment and management that a company believes should apply to standard hydraulic fracturing, but is an onerous requirement no necessarily applicable to nitrogen stimulation of vertical CBM wells. Nitrogen is an inert gas that the company believes should be treated differently than large volumes of water and sand, as well as small volumes of chemical additives.		The ERCB believes that fracturing operations above or near the BGWP need a higher level of due diligence from the licensee.
8. Enforcement process		
Concerns were raised regarding penalties or remedial plans if impacts occurred to water wells or aquifers. Regulations should have clear intention of enforcement and with penalties reflecting the seriousness of noncompliances.	Public	Any licensee who does not meet existing requirements are subject to a response under the ERCB's *Directive 019: Compliance Assurance*.

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9. Environmental		
Number of wells placed on a section of land must be limited, due to cumulative effects of flaring and other emissions, and the heightened risk to water and to the integrity of natural land and farmland. Monitoring of air, water and soil surrounding the operation needs to occur before and after. Should include testing for the chemicals in the fracture fluid, the compounds formed when these chemicals combine.	Public	Some of the concerns raised are not within the jurisdiction of the ERCB; however, there are existing directives which contain requirements such as *Directive 060* and *Directive 059*.
Depending on the size of the hydraulic fracturing site and production levels, energy use, emissions, extent of surface impacts and footprint, is there a trigger point when an Environmental Impact Assessment could or would happen. Is there a trigger point?	Alberta Health	This is out of the scope of this directive.
Consider green completions for these types of wells (similar to those made to the PSSG committee in early 2000).		Green fracturing completion fluids can be utilized if they are demonstrated to have no adverse affects upon an aquifer as required in the directive.
10. Flaring		
Flaring should not be allowed except in emergency situations.	Public	All flaring operations must meet the requirements of *Directive 060*.
11. Flowback Water		
How is "flow back water" from fracturing operations disposed of?	Public	Fracture flowback fluids that are not recycled for reuse are considered oilfield waste and must be handled and disposed of in accordance with *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*.
12. Fracture Planning Zone (FPZ)		
How is the FPZ determined? What criteria is used to determine the zone?	Alberta Health	It is the responsibility of the licensee to use all means to meet the requirements. This can be done in numerous ways; therefore, it is up to the licensee to determine how it will determine the FPZ.
No section identified: FPZ definition - too general, possibly two definitions, one for interwellbore communication and one for aquifers, or explain the difference. At a minimum the definition should align with IRP 24.	Industry	Defined “FPZ” in the directive.
Section 3.3.2(b): Is FPZ determination of 2 X fracture half-length outlined in IRP 24 acceptable?		It is the responsibility of the licensee to use all means to meet the requirements. This can be done in numerous ways; therefore, it is up to the licensee to determine how it will determine the FPZ.
Section 3.3.2(d): What radius beyond the FPZ should an operator be utilizing to search for offset wells?		It is the responsibility of the licensee to use all means to meet the requirements. This can be done in numerous ways; therefore, it is up to the licensee to determine how it will determine the FPZ.

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Section 3.3.2(8)(d): Outside the FPZ is treated the same as inside the FPZ? This step is redundant - or just confusing.		This has been changed in the directive.
Section 4.3.2(15): There is conflict between the definition of an FPZ in the directive and IRP 24.		The ERCB's definition of FPZ does not align with IRP 24. The ERCB's definition has been included in the directive.
13. General		
Has serious misgivings about fracturing and would recommend us research Dr. Anthony Ingraffea-Dwight C. Baum, Professor of Engineering, Weiss Presidential Teaching Fellow at Cornell University.	Public	There is a history of hydraulic fracturing within Alberta for many years. The ERCB evaluates hazards in the industry and creates appropriate requirements as needed.
Regulatory framework section needs to be better developed to help connect the dots between all applicable directives for this process.	Alberta Health	The ERCB agrees with this statement.
14. Geological		
No horizontal fracturing should be allowed where natural faults occur.	Public	Faults along with the other natural geological features that may serve as pathways have been included in the directive.
15. Impacts		
Hydraulic fracturing is not suitable for populated areas.	Public	There is a history of hydraulic fracturing within Alberta for many years. The ERCB evaluates hazards in the industry and creates appropriate requirements as needed.
Should study larger areas that could be affected.		This would be covered through the risk assessment in section 3.3.2 of the directive.
Section 1.2: A definition of "surface impacts" is not provided and without a specific definition "prevents of surface impacts" becomes too broad and impossible to achieve as hydraulic fracturing operations will always have a temporary surface impact.	Industry	The scope of this directive is subsurface issues. Surface issues are dealt with in other existing or pending regulations.
16. Information Transfer		
An effective, transparent and timely process for information transfer in an objective manner free from political interference.	Public	All stakeholders can access information through the ERCB website or through ERCB Information Services.
17. Injection Pressure		
Explain the inconsistence between the injection pressure required to fracture formations with hydrocarbon resources and the limits on the Classes I, II and III well head injection pressures, as stated in Section 8 of Directive 051 that limits injection pressure to a maximum of 90% of the receiving formation fracture pressure.	Public	*Directive 051: Wellbore Injection Requirements* allows a mini-fracture to evaluate formation characteristics and therefore limits injection pressures. The wellhead injection pressures are limited to ensure there is no fracturing of the formation during daily operations. This is a different scenario than hydraulically fracturing a formation to increase permeability.

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18. Inspections		
Wells should be inspected at all stages of active operation and regularly after they have been abandoned.	Public	This is outside the scope of this directive.
19. Interim Industry Recommended Practice 24 (IRP) 24		
No section: IRP definitions do not align with the directive.	Industry	The ERCB accepts that the IRP definitions do not align with the directive.
Section 3.3.2(10): The final paragraph of this section could be interpreted to be contrary to the first statement in IRP 24.		The ERCB recognizes and understands the position in IRP 24; however, no changes were made to the directive.
Section 4.3.2: Implies the FPZ is a volume. In earlier drafts of IRP 24 FPZ was proposed as a volume but in recent versions the FPZ is a surface area only. Secondly, at this time the FPZ was developed for analysis regarding interwellbore communication only. Further the directive definition of FPZ does not align with the IRP 24 definition.		Changed wording in section 4.3.2 of the directive to reference the modelled fracture vertical height.
Section 4.3.2(14): IRP 24 is about wellbore communication not groundwater protection. Its intention is not to risk assess water wells, nor does it elaborate on risk assessment for groundwater protection. This requirement should be deleted.		The ERCB understands that IRP 24 regards wellbore communication; however, this directive's intention is to prevent the loss of well integrity, reduce the risks of interwellbore communication, maintain well control of an offset well in the event of interwellbore communication, prevent adverse effects to nonsaline aquifers, prevent impacts to water wells, and prevent surface and subsurface impacts.
20. Interwellbore Communication		
Lack of clarity in regards to risk management requirements to address inter-wellbore communication between a subject well and non-offset wells.	Alberta Health	The directive addresses at-risk offset wells. If the well is not at risk, it is not considered by the directive.
21. Lack of Criteria/Requirement		
No requirement to notify surrounding community or the landowner of an "infraction".	Public	This is outside the scope of this directive.
The FPZ definition is vague and subjective. The zone should have criteria and include certain types of areas (at a minimum).	Alberta Health	Defined "FPZ" in the directive.
23. Monitoring		
Cement casing must be continuously monitored for any possible cracking during the entire life of the well.	Public	Added a requirement in section 2.3.3 of the directive.
24. Nonsaline Aquifers		
Set the criteria above the acceptable standards for human use. "The acceptable salinity level is identified to be 500 ppm and the acceptable TDS level to be under 1000 mg/l according to Canadian Drinking Water Standards. The standard of 4000 mg/l is recognized only by the oil and gas industry".	Public	The directive already sets the criteria above the acceptable standards for human use by protecting all nonsaline water above the BGWP. 4000 mg/L is defined by the *Water Act*. 4000 mg/L is more conservative than the *Canadian Drinking Water Standard*, which protects groundwater that can be treated prior

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		to use as well as the groundwater that is suitable for human consumption in its natural state.
Concerned that hydro fracturing may have the ability to effect allowing gases or hydrocarbons into the water aquifers.		The directive increased the water well protection zone around an existing water well (set out in section 4.3.2) to prevent adverse effects to the nonsaline aquifers; the directive further restricts the use of fracturing fluids that may cause adverse effects to nonsaline groundwater.
No section identified: A nonsaline aquifer is defined as an aquifer containing water with a TDS of less than 4,000 milligrams per litre. This should not be confused with potable or drinking water which has a TDS considerably less.	Industry	Defined “nonsaline aquifer” and “BGWP” in the directive. The directive does not use term “potable” or “drinking” in reference to the quality of the groundwater.
25. Notification		
Five day notification prior to commencement of fracturing operations is too narrow.	Public	This timeframe is adequate as an operational notification. The ERCB will monitor and adjust the timeframe as needed.
Section 8(25): Change notification requirement to 24 hours prior to the beginning of fracture stimulation or suggest changing wording to "a licensee must notify the appropriate ERCB field centre via the ERCB DDS system a minimum of 5 days prior to hydraulic fracturing pumping operations. One notification is required for all hydraulic fracturing operations on one pad. Clarification that notification applies to commencement of the first stage only, per pad or each well per pad, and the period of time the notification would occur.	Industry	This timeframe is adequate as an operational notification. The ERCB will monitor and adjust the timeframe as needed. A clarification statement was added in section 8 of the directive.
26. Offset Wells		
No section identified: The requirement that a well licensee must engage licensees of offset wells and make all reasonable efforts to develop mutually acceptable control and mitigation measures raises questions. What is the outcome if the offset well licensee fails to engage and work cooperatively in a timely manner? Any failure to resolve these issues could effectively shut down the first licensee's development schedule. Cost and liability questions arising on topics such as reliance on the other licensee's information when designing well control measures or the imposition of obligations on the offset well licensee to implement control measures (or face ERCB enforcement action).	Industry	The directive requires subject well licensees to (a) engage licensees of at-risk offset wells and (b) make reasonable efforts at developing well control plans that are mutually acceptable to both licensees. It is recommended that licensees document all efforts with regard to (a) and (b) above. Licensees of offset wells have an interest in engaging in the development of well control plans and designing and implementing any necessary well control measures to ensure compliance with the requirement that both offset and subject well licensees are responsible for maintaining control of their licensed wells at all times. Issues regarding licensee compliance with ERCB requirements would be assessed by the ERCB on a case-by-case basis. However, poor quality or reliability of offset well information does not alleviate a licensee from complying with requirements in the directive. Any licensee who does not meet existing requirements is subject to a response under the ERCB’s *Directive 019: Compliance Assurance.*

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Section 3.3.2: If an offset well is abandoned or orphaned, clarify who is to be notified and who will monitor them.		Clarified in section 3.3.4 how industry is to handle notification and engagement of at-risk offset wells which may be abandoned, orphaned or do not have an active licensee.
27. Protection of Interests		
No mention of the public, the surface owner or residents and how their interests will be protected.	Public	This is outside the scope of this directive.
28. Reclamation Costs		
Reclamation costs should be paid by the industry and not by taxpayers – understanding that there are insufficient funds being allocated by industry to address long-term reclamation costs for oil sands projects and oil wells.	Public	This is outside the jurisdiction of the ERCB.
30. Requirements – New/Remove		
Pipelines should be "double piped".	Public	This is outside the scope of this directive.
No section: There is a need to reflect inter-wellbore communication with other subsurface uses such as CO_2 injection wells, and gas storage wells and fields, among others.	Industry	This is outside the scope of this directive; however, a general statement has been included in the directive to raise awareness of these concerns.
Section 3.0: A new section should be added to prevent communication between a subject well and a commercial gas storage scheme."		This is outside the scope of this directive.
Section 3.3.2(9): This requirement is redundant and unnecessary; these requirements are adequately covered off in item 10.		These are two separate and distinct requirements.
Section 2.3.3(4)(d): Suggest this requirement is not required providing that (a), (b) and (c) are conducted. Modify that (d) to read that documentation will be supplied that the design of the single-barrier provides integrity.		Revised section 2.3.3 of the directive for clarity.
32. Responsibility		
Section 3.3.2(8)(e)(f)(g): This section should be the responsibility of the offset well licensee, not the subject licensee.	Industry	It is clearly stated in the directive that each licensee is responsible for its own well.
Section 3.3.2(10): Paragraph 3 suggests both the subject well operator and the offset well operator are responsible for a well control event. The company disagrees. The subject well operator is responsible for an interwellbore communication well control event that occurs as the result of a fracture stimulation from the subject operator's well. If something goes wrong, the subject well operator is responsible for the well control event, and enforcement action should only be taken against the subject well operator, unless the offset operator did not complete the actions agreed upon to secure or control the well or has assumed liability in which case the offset well operator would receive enforcement action.		Licensees of offset wells have an interest in engaging in the development of well control plans and designing and implementing any necessary well control measures to ensure compliance with the requirement that both offset and subject well licensees are responsible for maintaining control of their licensed wells at all times. Issues regarding licensee compliance with ERCB requirements would be assessed by the ERCB on a case-by-case basis. Any licensee who does not meet existing requirements is subject to a response under *Directive 019.*

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34. Technical		
Single-barrier wellbore construction should not be permitted.	Public	There is no evidence to suggest that single-barrier wellbore construction should not be permitted.
Lack of clarity regarding what the risk assessment needs to include.	Alberta Health	It is the responsibility of the licensee to use all means to meet the requirements.
36. Waste		
Nothing said on the characterization, classification and recovery/disposal options for fracturing waste.	Public	This is outside the scope of this directive.
37. Water		
Concerns regarding how water resources may be affected by fracturing – request that all water in the area that may be affected be tested before and after fracturing operations. A complete study of groundwater and wells before beginning any fracturing operation - should include isotope data to identify problem gas. Landowners should be provided a certified analysis of all water sources on or adjoining their property before fracturing begins and retested as needed. Tracers must be inserted into all fracturing fluids so that individual company can be held liable in case of water contamination.	Public	Environment and Sustainable Resource Development (ESRD) is currently reviewing the suitability of existing Baseline Water Well Testing Standards (BWWT) for multi-stage hydraulic fracturing associated with oil and gas development in tight sands and shales.
Fracture fluids enter geological formations at great depths below the ground water - consider depth of groundwater, depth of fracturing operations and oil/gas casings which leak after a certain age.		The risk assessment requirements in section 4.3.2 of the directive will deal with these issues.
Concerned with the amount of potable water being used in these procedures that is lost into the earth.		Industry is expected to maximize reuse of fracture flowback and the use of alternate nonsaline water sources and achieve the outcome of maintaining sustainable levels of nonsaline water use. These issues may be dealt with in future regulations.
Will the directive identify what type of water must be used for fracturing operations?	Municipal Government	The directive does not identify the type of water to be used for fracturing, but the ERCB will monitor the volume, quality, and source of fracture water used through *Directive 059*.
Do the companies have to use treated potable water for the fracturing process?		No, and many of the formations being fractured can use saline water.
We are noticing and being told that fracturing operations require treated potable water versus raw water from other sources such as dug outs, rivers, streams, and lakes.		Potable water is not required. All surface water sources listed can be used for fracturing fluids.
Water is a valuable and finite resource - the lack of a dedicated, accessible reporting tool which identifies the source, amount and type of water used in each fracturing operation. Creating a requirement to provide this information would be beneficial.		All this information must be reported to the ERCB as per *Directive 059*.
Reduce overall water consumption as well as alternative systems and technology to protect precious water resources.		Industry is expected maximize reuse of fracture flowback and the use of alternate nonsaline water sources and achieve the outcome of maintaining sustainable levels of nonsaline water use. These issues may be dealt with in future regulations.

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38. Water Well		
Are there any implications for existing approvals that are within the water well zone as described in Section 5.3.17?	Municipal Government / Alberta Health	All energy wells need to meet requirements.
The directive should include or refer to domestic water well testing 300 metres outside of the 200 metre restricted zone before and after the fracturing operation.		ESRD is currently reviewing and plans to revise the BWWT standards that will deal with water well testing distances from energy wells.
Section 5 refers to drinking water wells, does not include wells used for livestock.		Defined “water wells.”
What about landowners who need to drill water wells in the future? Will they be affected? Will they be limited to where they can drill?		Section 4 addresses nonsaline aquifer protection to address potential future groundwater use.
How will they find out about potential impacts to the aquifer from any type of oil and gas operation?		Alberta Agriculture and Rural Development provides a web-based Water Quality Information Tool and recommends regular testing of the private water supplies. ESRD maintains a water well complaints line which can be accessed if adverse effect from industrial activity is suspected.
Clarify what is meant by "bottom of the water well".		Removed the reference to “bottom of the water well.”
Section 5: Define "water well". Does this include brackish?	Industry	Defined “water well.”
Section 5.2: Does this pertain to all water wells; domestic, industrial, licensed and unlicensed?		Defined “water well.”
Section 5.3: Can you clarify Figure #1, is it acceptable to drill vertically through the 200 metre "no fracture" radius around a water well as long as any fracture operations are taking place >100 metres below the total depth of the water well?		Drilling needs to be dealt with through the well licence application. Currently there are no requirements not to drill within 100m of a water well.
39. Well Integrity		
How a single well with a single-barrier protection system can contain the fracturing fluids in case of loss of fracturing well physical integrity?	Public	Added additional requirements in section 2.3.3 of the directive to address these concerns.
Section 1.2: What is meant by "prevent the loss of well integrity"? Does this presume surface only or downhole as well?	Industry	The loss of well integrity is the escape of fluids (liquids or gases) through the well to an unintended subsurface formation or the surface.
Section 2.2: How does the ERCB define well integrity? By what criteria?		Defined “well integrity.”
Section 2.3.2(3): In situations where there is liner and intermediate casing, is this considered a single-barrier or dual-barrier system? Clarify intention.		Defined “single-barrier system” and “dual-barrier system.”
Section 2.3.3: Will the licensee be required to provide a risk assessment for the use of a single-barrier system?		Licensees are required to prepare a risk assessment; the ERCB will determine if they want to look at it.

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Section 2.3.3(4)(e): How can you demonstrate well integrity, by what/whose criteria? By what techniques and methodologies? Does this require pressure-test and bond log for the whole wellbore before and after the fracture? Casing inspection logs? What factors (i.e., size of fracture) may impact the demonstration of well integrity?		It is the responsibility of the licensee to use all means to meet the requirements. This can be done in numerous ways; therefore, it is up to the licensee to determine how it will demonstrate well integrity.
Section 3.3.2(e): What level of detail is required when assessing offset wellbore integrity, has the ERCB considered the level of detail required; cement top, casing design, well status (abandoned or active)?		It is the responsibility of the licensee to use all means to meet the requirements. This can be done in numerous ways; therefore, it is up to the licensee to determine how it will demonstrate offset wellbore integrity.