Frequently Asked Questions

Directive 083: Hydraulic Fracturing – Subsurface Integrity

January 2016

Q1. How does the AER differentiate between a dual- and single-barrier system?

A1. A dual-barrier system has an annular area that can be monitored for pressure and flow between a primary barrier and a secondary barrier. This area must extend from the wellhead to the base of the first porosity interval above the formation that will be hydraulically fractured (figure 1).

A dual-barrier system has a secondary barrier that is not the surface casing. This secondary barrier is a casing or liner that is run to surface. The primary barrier can be a liner, a casing string, or a tubing string with a device that isolates the primary barrier from the second barrier. The isolation device, or packer, must be located below the base of the first porosity interval above the formation that will be hydraulically fractured.

A single-barrier system does not have an annulus that can be monitored to the base of the first porosity interval above the formation that will be hydraulically fractured. It may consist of only one string of casing (figure 2).

Surface casing is not considered a part of the barrier system.

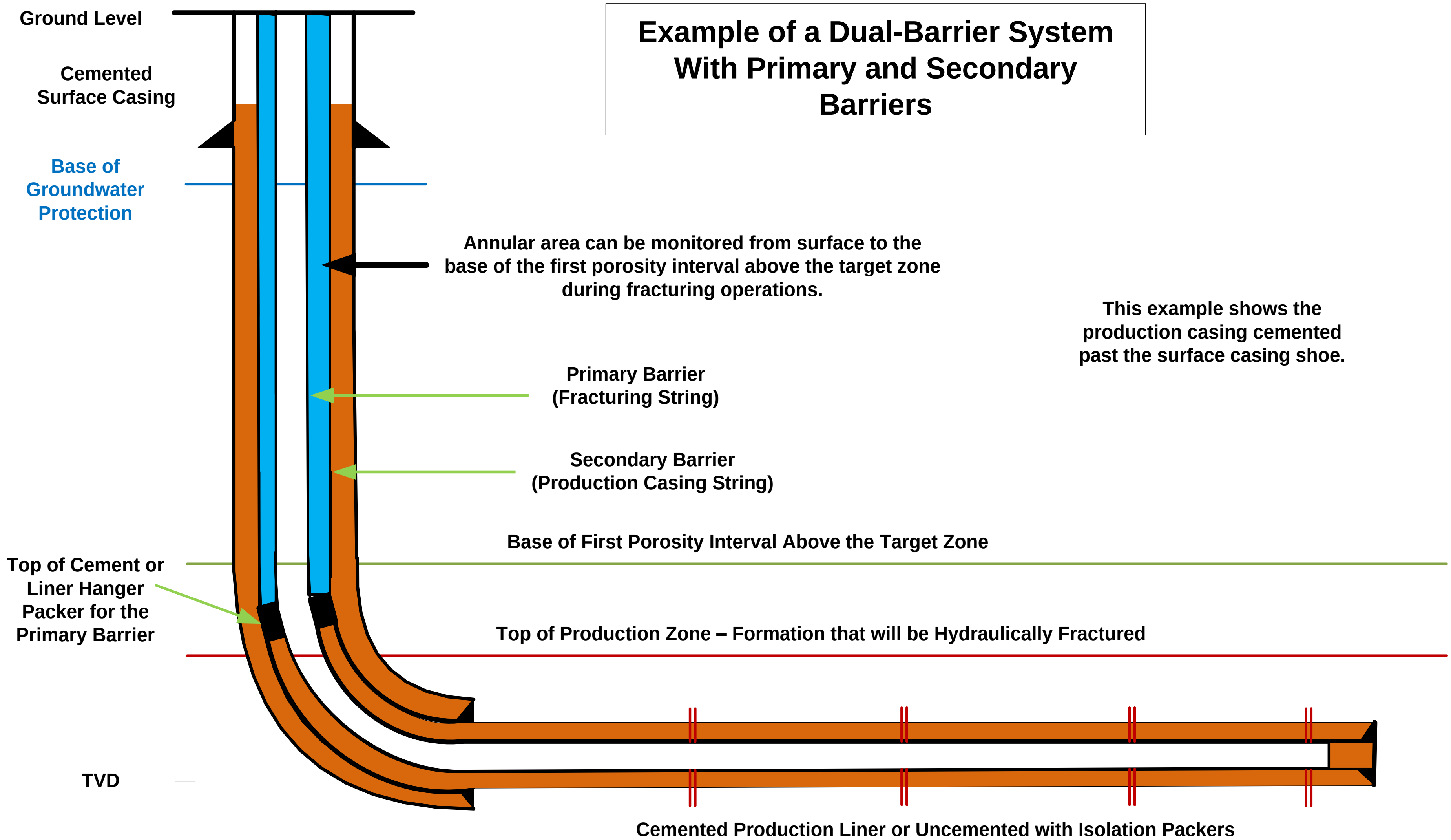
Q2. Can a well be classified as a single-barrier system when intermediate casing is run?

A2. Yes, but it depends on the design of the well and if the hydraulic fracture will be pumped down a primary barrier other than the intermediate casing (secondary barrier). When running intermediate casing, a well is classified as a single-barrier system if the intermediate casing has been landed and cemented above the base of the first porosity interval that is above the formation that will be hydraulically fractured.

A well can also be classified as a single-barrier system if the intermediate casing has been landed and cemented below the base of the first porosity interval, but only if the liner hanger packer for the next casing string has also been landed above the base of the first porosity interval.

Figure 1

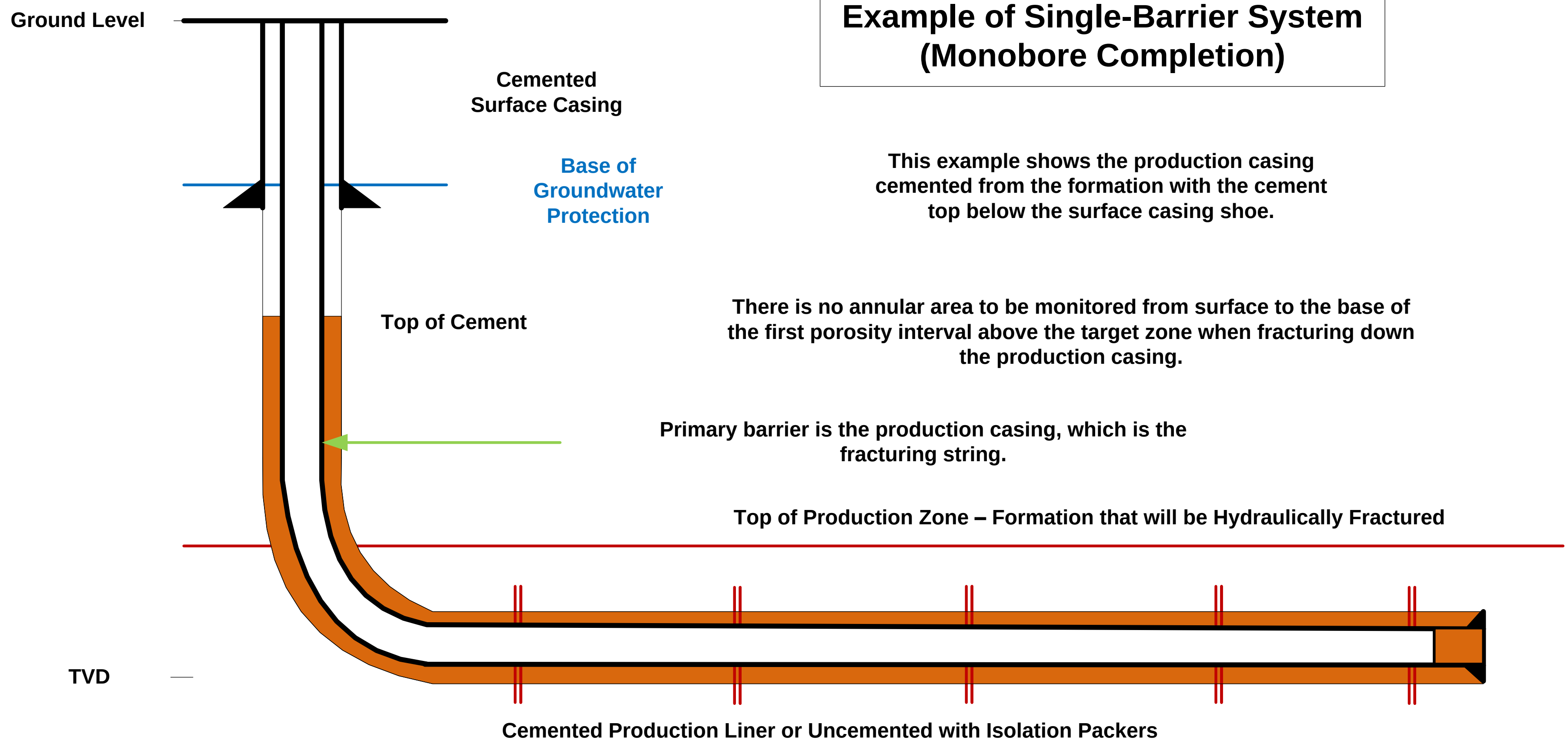
Example of a Dual-Barrier System With Primary and Secondary Barriers



The primary barrier can be coiled tubing provided that the fracture pressure is contained inside of the coil and the annular area can be monitored as indicated.

Figure 2

Example of Single-Barrier System (Monobore Completion)



This example shows the production casing cemented from the formation with the cement top below the surface casing shoe.

There is no annular area to be monitored from surface to the base of the first porosity interval above the target zone when fracturing down the production casing.

Primary barrier is the production casing, which is the fracturing string.

When fracturing with coil, the primary barrier is the production casing when the fracture pressure is outside of the coil.

Q3. **When you conduct a hydraulic fracture with coiled tubing (coil), is the well a dual-barrier or single-barrier system?**

A3. It depends on the completion design of the well. To qualify as a dual-barrier system, the second barrier (casing) must not be exposed to the pressure of the hydraulic fracture.

With coil, it is a dual-barrier system when the hydraulic fracture fluid is pumped down inside the coil and fracture isolation packers are run with the coil to contain the pressure of the hydraulic fracture.

If the wellbore would be classified as single barrier without coil in the well, and if the hydraulic fracture fluid is pumped down the outside of the coil, it remains a single-barrier system.

Q4. **How should I design and construct a dual-barrier well, or system, to maintain well integrity before, during, and after a hydraulic fracture?**

A4. Licensees must maintain the integrity of the casing and maintain hydraulic isolation between formations for the life of the well. The casing of a well should be designed, and the well constructed, for all service and operating conditions of the well life cycle. Although your target formation may not be sour at present, another formation completed in the future could be. If your well is not properly cemented, the casing could be exposed to a sour formation that was not planned for production or injection. Maintain casing integrity by ensuring that

- the burst pressure of the primary barrier (tubing or liner) is high enough to contain the pressure of the hydraulic fracture and is able to withstand any other conditions or loads exerted on the well while that barrier is in place,
- the secondary barrier is able to maintain control of the well if the primary barrier fails (the burst pressure of the second barrier does not need to be able to withstand the pressure of the hydraulic fracture if an effective pressure relief and containment system is installed), and
- the burst and collapse pressures of each barrier are adjusted at the maximum dogleg (bend) in the wellbore.

Note that cement is not considered a barrier in *Directive 083: Hydraulic Fracturing – Subsurface Integrity*.

Maintain hydraulic isolation between formations by

- ensuring that the barrier next to the rock maintains hydraulic isolation between porosity intervals during all phases throughout the life of the well (cement is normally used to isolate intervals) and
- identifying the potential for maintaining hydraulic isolation when fracturing.

To ensure that hydraulic isolation when fracturing can be maintained, an appropriate cement evaluation log (CBL) on the casing or liner could be run. The CBL should be run from the top of the formation being fractured to a point above the surface casing shoe. Licensees are not required to run a CBL nor does a CBL provide conclusive evidence of hydraulic isolation. Other technical methods or procedures may be used during or after hydraulic fracturing to assess whether hydraulic isolation has been maintained.

In addition to the above, licensees must also meet or exceed all AER regulations and industry best practices for the design and construction of a well.

Q5. What steps can I take to demonstrate due diligence for well integrity at the well construction stage.

A5. A licensee should confirm that technically acceptable methods were used to provide assurance of casing and cement integrity . The AER recommends that the following procedures be recorded, with evidence available, to indicate compliance with the stated procedures:

- Identify the drilling best practices that were followed to ensure good hole conditions before running casing and when cementing the casing. Include any additional measures that were implemented beyond the current rules and best practices.
- Identify how the casing and casing connections were designed to last the entire life of the well and to meet the well's service conditions. Include all of the tri-axial loads, temperature effects, and pressures that the casing may be exposed to during fracture stimulation, fracture flow back, and production operations.
- Identify the cementing best practices that were followed to ensure an optimal primary cement job and hydraulic isolation throughout the wellbore. Include any additional measures that were followed beyond the current rules and best practices. This should include casing centralization (standoff percentage).
- Record all data that provides evidence demonstrating that a high-quality primary cement job was achieved.

Q6. How can I maintain well integrity before, during, and after a hydraulic fracture on a dual-barrier system?

A6. A licensee should confirm that technically acceptable method was used to confirm casing integrity. To maintain well integrity in a dual-barrier system, the AER recommends following these guidelines:

1) Take the following measures to contain the hydraulic fracture in the target formation:

   - Before and after a hydraulic fracture, conduct surface casing vent flow (SCVF) and gas migration (GM) tests on the subject well and on offset wells in the fracture planning zone (FPZ) or other special consideration wells that are considered at risk for inter-wellbore communication. (Enform's Industry Recommended Practice (IRP) 24: Fracture Stimulation; Interwellbore Communication provides more guidance on what constitutes an "at-risk" well.)
   - Design the hydraulic fracture and make any adjustments necessary during the fracture operation to ensure that the fracture itself stays in the formation (e.g., pump rate, treatment pressure, slurry volume, and fluid properties).
   - On older offset wells considered at risk of well integrity failure, a CBL or a casing inspection log may need to be run. Noise and temperature logs may also be used to determine if there is cross-flow out of the fractured formation.

2) Ensure that the casing is not damaged by using pressure limits, corrosion control, and other measures. The following are some of the measures that could be used:

   - Run a pressure test on the intermediate casing after it has been cemented in place and before resuming drilling to confirm the initial integrity of the casing. The pressure test needs to confirm that casing integrity exists from surface to a point below the base of the first porosity interval. Consider running this pressure test for a minimum of 10 minutes at the maximum pressure that the casing may be exposed to during fracturing operations if that pressure exceeds 7 mPa.
   - For wells with intermediate casing and a liner, ball-drop, ported system used in multistage hydraulic fracturing, a "pressure up and hold" test with a ball drop could be run at any stage. This will confirm integrity of the hydraulic fracture string and liner (primary barrier) at that point in time. The test pressure cannot exceed the port opening pressure. If performed during the final stage of a multistage hydraulic fracturing operation, and if the pressure of the final hydraulic fracture is not greater than the pressure of any of the previous stages, it can be argued that casing integrity has been maintained post-hydraulic fracture. A pressure test of this nature should be

done with noncompressible (i.e., nonenergized) fluids and should be conducted for a 10-minute period.

- Monitor the annular area between the primary and secondary barrier during the hydraulic fracturing operation to detect a failure of the primary barrier. A pressure relief system on the annulus may need to be installed to prevent the secondary barrier from exceeding burst pressure. The AER also recommends using a containment system with a pressure relief system to safely hold any fluids that could be released from the well.
- Run an additional ball and seat assembly, without a port, to conduct a final pressure test after completing all hydraulic fracturing stages to confirm integrity of the primary barrier. Setting a retrievable plug, bridge plug, or a packer in the casing later on and then pressure testing the casing is also acceptable.
- Monitor the pumping rate and pressure during your hydraulic fracturing operations for abnormalities that may suggest a well integrity failure.

3) Have an overall risk management plan in place for your operations. This plan must comply with *Directive 083* requirements and be supported with technical and operational evidence. Licensees must conduct all hydraulic fracturing operations in accordance with this plan and keep detailed records of all operations.

Q7. How should I demonstrate the integrity of the casing and the well, or system, before, during, and after a hydraulic fracturing operation on monobore wells or other single-barrier systems?

A7. In addition to following the general guidelines above for a dual-barrier system, ensure the following:

1) Contain the hydraulic fracture in the target formation.

- Conducting surface casing vent flow (SCVF) and gas migration (GM) tests on the subject well, on wells in the fracture planning zone (FPZ), and on other offset wells that are considered at risk for inter-wellbore communication is recommended. When such testing is done, it should be done before and after hydraulic fracturing.
- The hydraulic fracture design and adjustments made while pumping the hydraulic fracture need to ensure that the fracture stays in the target formation(s). The factors to consider are pump rate, treatment pressure, slurry volume, and fluid properties.
- On older wells, running a CBL and/or a casing inspection logs may also be recommended if the well is considered at risk for well integrity failure. Noise and

temperature logs may also be used to determine if there is cross-flow out of the fractured formation.

- Consider additional measures to ensure and confirm that the cement job is premium quality. Possibly verify where casing centralizers were actually run by turning up the sensitivity on the casing collar locator (CCL) log as part of your quality control/quality assurance (QA/QC) program.

2) Ensure that the casing is not damaged by using pressure limits, corrosion control, and other measures.

   - Document the load capacity of the casing and demonstrate casing integrity before, during, and after hydraulic fracturing. The primary barrier must be able to withstand the pressure of hydraulic fracturing and any other conditions or loading placed on the well. Note: Cement is not considered a "barrier" in *Directive 083*.
   - Take and document any additional measures necessary to minimize damage to the casing connections and to reduce the risk of a casing connection leak. Some casing connections are highly susceptible to damage while handling, both when making connections and when running in the hole.
   - Run a pressure test on the casing after it is cemented in place to confirm the initial integrity of the casing. The casing pressure test needs to confirm that casing integrity exists from surface to a point below the base of the first porosity interval above the hydraulic fracture formation.
   - For wells with casing and a liner, ball-drop, ported system, which is common in multistage hydraulic fracturing, run a "pressure up and hold" test with a ball drop at any stage. This will confirm integrity of the hydraulic fracture string and liner at that point in time. The test pressure cannot exceed the port opening pressure. If performed during the final stage of a multistage hydraulic fracturing operation, and if the pressure of the final hydraulic fracture is not greater than the pressure of any of the previous stages, it can be said that casing integrity has been maintained post-hydraulic fracture.
   - An additional ball and seat assembly could also be run, without a port, to conduct a final pressure test after all hydraulic fracturing stages are completed to confirm integrity of the casing. Setting a retrievable plug, bridge plug, or a packer in the casing after the hydraulic fracture and then pressure testing the casing is also acceptable.

- During hydraulic fracturing operations, the pumping rate and pressure should be monitored for abnormalities that may suggest a well integrity failure.

3) Have an overall risk management plan in place for your operations. You need to ensure that this plan complies with *Directive 083* requirements, with supporting technical and operational evidence, and you must conduct your hydraulic fracturing operations in accordance with this plan.

   - Single-barrier and monobore well designs require more diligence than dual-barrier systems to be classified as equivalent to dual-barrier systems. Licensees must be able to compensate for the fact that monobore well designs do not have an annulus and a second barrier for safety.
   - Ensure that the pressure from hydraulic fracturing is not communicated to the outside of the casing. If the primary cement job is compromised, the casing could collapse when flowing back the fracture fluids. With open hole, packer, and liner designs, an extra isolation packer could be run below the cement stage tool to reduce the risk of collapsing the casing while flowing back the well after the hydraulic fracturing operation due to trapped pressure.
   - Strictly follow industry cementing best practices during the primary cementing operation.
   - On horizontal and directional wells, a calculation to adjust the burst and collapse pressures of the casing (i.e., the hydraulic fracture string) should be done at the maximum dogleg in the well.
   - Keep detailed records of all of operations.

4) Some issues to address with monobore wells and hybrid monobore wells are as follows:

   - Minimizing casing centralization due to concerns with torque and drag when running the casing and liner assembly in the hole before cementing could result in a poor cement job.
   - Monobore designs may not allow for reciprocation and rotation of the pipe when cementing, which further compromises cementing best practices. This is an area of emerging technology that needs to be addressed with updates to Enform industry recommended practices (IRPs) and other industry best practices.

Q8. Will the AER accept running a few representative cement evaluation logs in a field or from a pad rather than on every well when demonstrating well integrity?

A8. The AER will determine this on a case-by-case basis.

Q9. Is there a specific change in pressure that defines what inter-wellbore communication is?

A9. No. At the present time, the licensee must report all inter-wellbore communication events to the AER regardless of the pressure. This practice is currently under review.

Q10. How do I report an inter-wellbore communication event to the AER?

A10. Notify the appropriate AER field centre and complete the AER Hydraulic Fracturing Communication Event Form available on the *Directive 083* page of the AER website, www.aer.ca, or from any AER field centre. After notifying the appropriate AER field centre, e-mail this form to HF_Notification@aer.ca.

Q11. What constitutes five days' notification for a hydraulic fracture?

A11. A minimum of five days' notification is 120 hours from the time that the AER is notified of a planned hydraulic fracture to when the hydraulic fracture has been set to occur.

Q12. How do I notify the AER of a planned hydraulic fracture?

A12. Complete the AER Hydraulic Fracturing Notification Form and e-mail it to HF_notification@aer.ca. The AER notification form is available on the *Directive 083* page of the AER website, www.aer.ca.

Q13. Do I have to give notification through the Digital Data Submissions (DDS) system of a planned hydraulic fracture as well as by e-mail?

A13. Yes. You should continue to notify the AER of a hydraulic fracture both through the DDS system and by e-mail.

Q14. Is there a specific time when I must notify the licensee of an offset well that is considered to be at risk for inter-wellbore communication during the fracturing operation?

A14. No. Licensees planning hydraulic fracturing are expected to develop mutually acceptable risk management plans with licensees of offset wells that are considered to be at risk. Each licensee is responsible for the control of its own well.

See Enform's Industry Recommended Practice (IRP) 24: Fracture Stimulation: Interwellbore Communication for guidance on developing risk management plans. IRP 24 also has a link to a risk registry that may provide further guidance on risk evaluations.

Q15. Whose responsibility is it to identify manned operations, such as drilling or well servicing, that are offsetting a fracturing operation?

A15. The licensee of the well that is being fractured has the responsibility to notify offset licensees. However, all licensees/operators are expected to maintain a high level of communication with other licensees/operators to prevent accidents and adverse impacts.

A high level of communication is also expected to be maintained within company departments to prevent accidents and adverse impacts.

There is no single source to identify the daily activities of all manned operations that may occur on a well. One of the most important methods is diligent daily field scouting.

Q16. Q16. As the licensee of a well that is offset from a well planned for a hydraulic fracture, am I able to object to the hydraulic fracture operation?

A16. Section 32 of the Responsible Energy Development Act states that any person who believes that they may be directly and adversely affected by an application may file a statement of concern with the regulator in accordance with the rules. Alternatively, you may contact your local AER field centre with your operational concerns.

Q17. Is there a recommended method for monitoring abandoned wells?

A17. No. The AER does not endorse any specific method. The AER encourages industry to consider all options available, including emerging technology such as microseismic.

Q18. If a well screens out (i.e., sands off) during a multistage hydraulic fracturing operation and there are still several days before the operation is to continue, do I need to re-notify the AER?

A18. No. As a guideline, you are expected to re-notify the AER if the hydraulic fracture fleet is demobilized and then is to be remobilized.

Q19. If the fracture planning zone (FPZ) is small and if offset wells are a long distance away from the target wellbore, do I need to notify the licensees of the offset wells? Do I need to monitor the offset wells when they are considered at risk?

A19. It is up to the licensee to determine the risk and to arrange monitoring of wells that are considered at risk. If it is believed that there are offset wells at risk of inter-wellbore communication, the licensee must attempt to notify the licensee of those offset wells. There will be circumstances where the licensee of a well planned for hydraulic fracturing does not believe any offset wells are at risk. In any case, any risk assessments form a part of the at-risk well control plans as described by requirement 12 of *Directive 083*.

AER field inspectors will do their own assessment of the risks through field reviews. See Enform's IRP 24 for guidance on how to determine the FPZ.

Q20. Do I need to notify the AER of a diagnostic fracture injection test (DFIT)?

A20. No. If the DFIT injection volumes are small, the risk of a well integrity failure or inter-wellbore communication is low.

Q21. Is notification required for each well on a pad when the hydraulic fracturing is expected to be continuous on the pad?

A21. No. The unique well identifier (UWI) of each well on a pad that is planned for hydraulic fracturing should be listed on one notification form rather than providing a separate form for each UWI.

Q22. What methods can I use to determine the FPZ?

A22. Although the AER does not specify how to determine the FPZ, you need to consider the characteristics of the formation you will be fracturing and the risk of long-distance communication events with the method you do use.

FPZs are commonly assessed using hydraulic fracture modelling software. When using such software, the more detailed the information is on the formation to be fractured, the more meaningful your description of the fracture geometry will be. You may also use other evaluation methods to determine the FPZ, such as a representative model of the formation and surrounding area that has been adjusted for the size of the hydraulic fracture and the amount of proppant and volume of hydraulic fracture fluid to be used.

Q23. How do I determine the distance from a hydraulic fracturing operation at which an offset well would be considered at risk of inter-wellbore communication?

A23. The AER does not specify how to determine this distance. However, be aware that the distance at which inter-wellbore communication can occur is often underestimated. Preliminary reporting indicates that about 10 per cent of these events occur at distances greater than 1100 metres. This distance can also vary significantly, particularly if you are using an energizing agent (N2 or CO2) in the hydraulic fracture fluid. You should also consider previous hydraulic fracturing done in the area.

Fracture half-length model distances have many variables and have a low correlation to actual communication events. This type of modelling attempts to predict how much of the rock will break.

The type of formation, the fracture design, the geological environment, and the reservoir characteristics are all important considerations.

Consult with your geological, reservoir, production, drilling, and completion teams to understand the nature of the formation being fractured and if any natural fractures may be present, as well as the surrounding depositional environment, the presence of conglomerates, high-permeability streaks, or enhanced recovery analysis.

Offset well monitoring during fracture operations will help licensees understand the area-specific and formation-specific communication distances in their specific operating fields.

Q24. What information sources may identify that a high-risk operation is occurring that is at risk of experiencing inter-wellbore communication from a fracturing activity?

A24. The AER expects licensees to conduct risk-based well and area reviews using public data and all of the practical data that the licensee has access to that may indicate that a high-risk activity is occurring near the fracturing operation.

One of the most important methods is to scout the area to identify drilling activity or well-servicing activity that may be at risk.

Licensees are expected to assess the risk of communication to offset wells and to implement a monitoring and mitigation plan if communication is considered to be a risk.

Some licensees have established risk protocols based on the status of drilling on an offset well (i.e. is the intermediate casing cemented in, is drill pipe in the hole, etc.?). ,

Q25. What leading indicators may identify the potential for long-distance interwell communication as a result of fracturing operations?

A25. Indicators such as lost circulation during drilling or possibly an interpretation of water flood performance may suggest high permeability or natural fractures in a formation. It is recommended that licensees examine all of the practical data that is available in their areas of operation and structure their own risk assessment models.

Q26. What are the lessons learned from licensees/operators who have experienced inter-wellbore communication as a result of fracturing activity while conducting a high-risk operation?

A26. There are two common themes from industry in this regard. One is the long distances over which inter-wellbore communication can occur. The second issue is communication breakdown, or lack of effective communication, between people conducting concurrent operations in the same area.

Long-term planning with a high level of communication is very important. At the present time, there is no single source to identify all of the activities occurring in a geographic area.

Overall operational awareness is critical. It is recommended that communication efforts be documented and that confirmation of the receipt of notifications be requested.

Licensees also reported that a negative test on well monitoring is not conclusive evidence that the fracture did not propagate in the direction of the well that was monitored.

Q27. Is there a method to identify whether manned operations are occurring on a well, or are there any ‘best practices’ to identify these operations?

A27. There is no single source to identify manned operations. The AER has been in discussion with industry licensees about possible methods of identifying manned operations and developing best practices or regulatory changes.

Q28. Does the AER specify downhole float equipment, bottomhole assemblies (BHA), liner packer and port systems, or tool designs?

A28. No. Industry recommended practices and well-design standards that affect well construction, BHA, and downhole tool designs are evolving.

Q29. How will the AER be conducting field reviews, inspections, and audits?

A29. The AER has not yet finalized the processes for conducting field reviews, inspections, and audits.

Q30. How do I become aware of new Directives or revisions to existing rules?

A30. When the AER releases revisions to existing rules or a new directive, it announces the change on its website, www.aer.ca. To keep up to date on changes being made at the AER, subscribe to either the RSS feed or twitter account.

Q31. What should I do if there are abandoned offset wells considered at risk for a hydraulic fracture that either have defunct licensees or are managed by the Orphan Well Association (OWA)?

A31. Notify the appropriate AER field centre of your risk assessment and the known status of the wells. You may need to adjust your hydraulic fracture plan so that the wells are no longer at risk. You may also transfer the licence of defunct or orphan wells to your company. To do this, send transfer requests by e-mail to LiabilityManagement@aer.ca. To transfer the well licence, mineral rights are not required, but road and surface leases are.

Q32. Can I transfer the licence of an abandoned offset well considered at risk for a planned hydraulic fracture if there are outstanding AER orders (closure, abandonment)?

A32. No. You may only transfer the well licence after all orders have been resolved. Send your request for a transfer by e-mail to LiabilityManagement@aer.ca.The AER will collect a fee for the transfer that will be paid to the OWA.

Q33. What kinds of wells cannot be transferred?

A33. Reclamation-certified and reclamation-exempt wells cannot be transferred (see Directive 006: Licensee Liability Rating [LLR] Program and Licence Transfer Process). If you wish to re-enter these wells, submit a Directive 056 application to the AER. For more information on how to classify a well or facility as reclamation exempt, e-mail the AER at RecRemApplications@aer.ca or call the Customer Contact Centre at 1-855-297-8311.

Q34. When hydraulic fracturing operations other than coalbed methane (CBM) occur above the base of groundwater protection, how do I determine which fluids will not have an adverse effect on the groundwater?

A34. Fracture fluids used above the base of groundwater protection should not contain hydrocarbon-based hydraulic fracture fluid, produced saline water, or other components that may have an adverse effect on nonsaline aquifers (see requirement 21 of Directive 083). Licensees are currently working with hydraulic fracture pumping companies to develop more environmentally friendly fluids and additives (surfactants, gelling agents, breakers, biocide, clay stabilizers, and corrosion inhibitors).

Q35. Will I still be required to give an AER field centre 48 hours' notice for HVP (high-vapour pressure using propane-butane) hydraulic fractures?

A35. No. You are required to provide five-days' notice by e-mail to HF_notification@aer.ca and via the DDS system. The letter you receive approving your HVP fracture will specify how you must meet the AER's notification requirements.

Q36. How did the AER determine the horizontal and vertical spacing requirements between a water well and a CBM well in Directive 083?

A36. The distances were derived from a 2008 study and a subsequent Society of Petroleum Engineers paper (SPE-135683) called Analysis of Nitrogen Simulation Technique in Shallow Coalbed-Methane Formations. (http://www.aer.ca/documents/directives/Directive027_Shallow_Fracturing_TaurusFinalReport.pdf).

The AER may review hydraulic fracture propagation in Alberta's shallow formations in future amendments of Directive 083.

Q37. When developing a risk management plan for a hydraulic fracture that I have planned, what kind of notification do I need to give the licensees of wells that are offset from the fracture and are at risk of inter-wellbore communication?

A37. The AER does not specify how notification is to be provided between the licensee of the subject well and other licensees.

The AER expects licensees of wells subject to a hydraulic fracture and licensees of offset wells that are at risk from the hydraulic fracture to work together to develop mutually acceptable risk management plans to prevent damage to offset wells and well integrity failures during a fracture. It is the responsibility of the licensee planning the hydraulic fracture to determine an acceptable process to manage risk. The AER may review this plan and recommend changes to it during a prehydraulic fracture review or audit.

Q38. What should I do if the licensee of an offset well or special consideration well is believed to be at risk and that licensee refuses to cooperate in developing a mutually acceptable risk management plan?

A38. If the licensee of an offset well that is at risk does not cooperate in developing a plan that works for both of you, the AER recommends that you minimize the risks by

- conducting a risk assessment of the offset wells (using public records and knowledge of the area),
- evaluating whether the size or design of the hydraulic fracturing operation should change (e.g., eliminate or reduce the number and size of some stages if fracturing a horizontal well), and
- considering other methods of active monitoring (microseismic).

Take any other steps that you believe are appropriate and necessary to mitigate risk. Each licensee is responsible for the control of the well licensed to it, regardless of the circumstances. As such, the AER does not impose settlements for damaged offset wells. However, it may conduct an audit or investigation or issue a form of compliance assurance under *Directive 019: Compliance Assurance*. A licensee should record all attempts to communicate with and the response received from the licensee of the offset well. The AER may ask for this information when conducting an audit or investigation.