Chapter 9 Well Activity:
Completion, Maintenance and Abandonment

# 9. Well Completions, Maintenance and Abandonment

**Please Note:**

This manual is written as a whole and provided to industry in sections to allow permit holders to access activity chapters. It is prudent of the permit holder to review the manual in its entirety and be aware of the content in other sections of the manual.

## 9.1 Well Equipment

Equipment must adhere to the regulatory requirements.

### 9.1.1 Wellheads

Wellheads are required to operate safely under the conditions anticipated during the life of the well and the wellhead is not to be subjected to excessive force. Review Enform's IRP Volume#5: Minimum Wellhead Requirements for more information.

### 9.1.2 Tubing

Tubing is required for the production of gas containing greater than or equal to five per cent $H_2S$ and for all injection and disposal except for the injection of fresh water. This excludes initial completions and/or hydraulic fracturing.

### 9.1.3 Packers

A production packer must be used for:

- All injection and disposal except for the injection of fresh water.
- Wells not on artificial lift, containing gas with greater than five per cent $H_2S$, or if a numbered highway or populated area is located within the emergency planning zone for the well.

  "populated area" means a dwelling, school, picnic ground or other place of public concourse.

  To facilitate future abandonments, packers are required to be set in the zone of interest or as close as reasonably possible to perforations.

Annual packer isolation testing is required for all regulated packer installations. The report is to be submitted to the OGC within 30 days of the test. If a packer test fails, the permit holder must complete the repairs without unreasonable delay.

Operators of disposal wells, injection wells and sour gas production wells should adhere to the requirements under the Drilling and Production Regulation Section 16(2) and Section 39(6):

- Set a production packer in the well as near as is practical above the injection interval or production formation, and fill the space between tubing and casing with corrosion and frost inhibiting fluid. This prevents production or injection fluids from contacting and potentially compromising the integrity of the well casing.

The Commission has defined a preferred PIT procedure, outlined in Appendix D of the Water Service Well Summary Information document. This procedure is based on the Alberta Energy Regulator's (AER) Interim Directive ID 2003-01, altered to provide a robust and consistent procedure delivering comparable results, and eliminating the need to choose a case method dependent on casing pressure upon arrival. PIT results are continually reviewed by the Commission and the testing procedure may be modified in the future if warranted.

## 9.1.4 Subsurface Safety Valves

Subsurface safety valves are required for wells containing gas with greater than five per cent $H_2S$ if:

- A major highway or populated area is located within the emergency planning zone for the well.
- The well is located within 800 metres of a populated area or eight km of a town, city or village.
- The well could produce > 30 $10^3m^3$ of gas per day.
- The well is an acid gas disposal well.

Function testing of the subsurface safety valve is required twice annually or as per the manufacturers recommended practice. Ensure the valve leak rate does not exceed the American Petroleum Institute's (API) RP 14B: Design, Installation, Repair and Operation of Subsurface Safety Valve Systems errata document.

In general, the distance from a city, town or village should be measured from the corporate limits. In cases where the corporate limits do not reasonably correspond with the boundaries of the community, the permit holder may take a functional approach such as delineation of the extent of developed areas.

## 9.1.5 Oil Wells

Oil wells completed after October 4, 2010 equipped with an artificial lift, if the $H_2S$ content of the gas exceeds 100 ppm, must install the following:

- If a pumpjack is the method of artificial lift:
  - install on the stuffing box a device that will seal off the well in the event of a polish rod failure, and
  - Automatic shutdown on the stuffing box that will shut down the pumping unit in the event of a stuffing box or polish rod failure.
  - Automatic vibration shutdown system.

- If a pumpjack is not used as an artificial lift, maintain a system that will shut down the artificial lift if a leak is detected.

### 9.1.6 Fencing

Permit holders of completed wells that:

- Are located within 800 metres of a populated area.
- Have a populated area within the emergency planning zone of the wells.

Fencing or other suitable measure to prevent unauthorized access to the well must be installed. An exemption can be requested if the intent of section 39 of the Drilling and Production Regulation is met or exceeded. For wells that are located on private land, the method of access control should be developed in consultation with the landowner.

## 9.2 Well Servicing Operations

### 9.2.1 Notice of Operations

A Notice of Operation (NOO) must be submitted for all work being performed on a well. This includes initial completions, completions workovers, abandonments and maintenance. The complete list can be found in the Commission's Notice of Operations and Completion / Workover Report Reference Guide. The NOO is to be submitted electronically through the eSubmission portal on the Commission's website.

The Notice of Operations submission requires the well authorization number and is submitted using eSubmission portal within at least 24 hours prior to the start of completion operations. Notice of Operations submitted at least 7 days prior to the start of abandonment operations.

If an activity at a well is expected to result in gas being flared, a Notice of Flare must be submitted using the eSubmission Portal. This Notice may be submitted in conjunction with a Notice of Operation if a well operation is taking place, or as a standalone submission.

To report actual flare volumes, ensure all volumes flared at a well are included in production reporting via Petrinex.

**Please Note:**

Shallow Fracturing operations at a depth of 600 metres or less must be approved in the well permit. Refer to the Commission's Oil and Gas Activity Application Manual for more information.

### 9.2.2 Inter-wellbore Communication

Subject well permit holders (the well undergoing hydraulic fracture stimulation) are obligated to manage the risks of inter-wellbore communication between the subject well and an offset well. The subject well permit holder must have a documented hydraulic fracturing program that includes the following elements:

- Identify all offset wells that could be affected.
- Conduct a risk assessment of the identified offset wells.
- Develop a well control plan for all offset wells that are at risk.
- Modify the hydraulic fracturing program if risks cannot be mitigated.

The subject well permit holder must notify the permit holder of an at-risk offset well of its planned hydraulic fracturing program and make all reasonable efforts to develop a mutually-agreeable well control plan. The subject well permit holder must maintain a copy of the at-risk well control plan for the duration of hydraulic fracturing operations.

The permit holder of an at-risk offset well, upon receiving notification of a planned hydraulic fracturing program, is expected to engage and work cooperatively with the subject well permit holder in development of well control plans.

During the design and execution of the fracturing program, the subject well permit holder must ensure the fracture will not extend into any unintended formations. Any communications with unintended formations are in conflict Section 22 of the Drilling and Production Regulation.

All fracture communication "incidents" must be reported in accordance with the Commission's Incident Reporting Instructions and Guidelines.  An incident means the communication resulted in a spill, equipment overpressure, equipment damage, injury or drilling kick. For inter-wellbore communications, a kick is defined as a pit gain of three cubic metres or greater, or a casing pressure of 85 per cent of the Maximum Allowable Casing Pressure (MACP).

Communication events should be reported even if contact did not reach the defined "incident" level. A database of all communication events will further the understanding of the resource and assist in the development of effective technology.

Permit holders are requested to report all fracture communication events using the Inter-Wellbore Communication Report Form. Permit holders are also expected to follow Enform's Industry Recommended Practice 24 for specific methodology and procedures regarding the inter-wellbore communication management process.

### 9.2.3 Multi-zone or Commingled Wells

Refer to Section 23 of the Drilling and Production Regulation.

All zones in a well must remain segregated unless permission has been granted for commingled production. Permission may be granted in an individual well permit or by a special project for commingling under Section 75 of OGAA.

For information and guidelines in regards to commingling, including forms and requirements, refer to the Commingling section within the Reservoir Engineering documentation page on the Commission's web site.

The Notification of Commingled Well Production form must be submitted to the Commission within 30 days of the commencement of commingled production.

## 9.3 Well Suspension

Activity means:

- Production, injection or disposal of fluids.
- Drilling, completion or workover operations.

Inactive well means a well that has not been abandoned but:

- Has not been active for 12 consecutive months.
- If the well is classified as a special sour or an acid gas disposal and has not been active for six consecutive months.

For active production, injection and disposal wells, the date of the last activity is defined as the first day of the month following the last month for which production, injection and disposal volumes were reported.

Observation wells are deemed to be active (see section 9.3.1 of this manual).

### Well Suspension Activity Dates

- For active production, injection and disposal wells, the date of last activity is defined as the first day of the month following the last month for which production, injection and disposal volumes were reported.
- For drilling activity, including new wells and re-entries, the date of last activity is defined as the rig release date.
- For completion and workover activity, the date of last activity is defined as the completion date.

A permit holder may apply to the Commission to declassify a special sour well. The context here is that as production rates fall, the $H_2S$ release rate may fall such that the well no longer should be classified as a special sour well.

## 9.3.1 Observation Wells

The Drilling and Production Regulation defines that a well or a portion of a well may be designated as an observation well under Section 2(7). Reservoir observation wells typically gather data on:

- Formation pressure, fluid quality or fluid migration related to production, injection or disposal.
- Monitoring well completion operations (microseismic) or seismicity observation.

For use of either a purpose-drilled well, or conversion of an existing production or injection well to observation type, an application and approval is required from the Reservoir Engineering Department of the Commission. An observation well designation under Section 2(7) contains conditions for monitoring, data collection and reporting to maintain a valid designation. After issuing approval, the Commission will update the well status to reflect the observation well designation.

A well permit holder must ensure that the static bottom hole pressure of each observation well is measured at least once per calendar year, unless stated otherwise in the approval. All static bottom hole pressure measurements and resulting shut-in time must be reported to the Commission.

Observation wells are treated as active and do not require suspension unless observation designation is withdrawn:

- Observation well designation may be withdrawn if approval conditions are not met.
- When observation well designation is withdrawn, the well status will revert the well operation status (i.e. Gas Production) existing prior to the classification as observation wells and may require suspension.

### 9.3.2 Suspension Requirements

All wells must be suspended within 60 days of attaining inactive status in a manner that ensures the ongoing integrity of the well.

Any well may be suspended to a higher standard than the minimum requirements described in Tables 9A to 9D. Reporting requirements are described in Section 9.5.1.

Permit holders may apply to the Commission Drilling and Production department for an extension of a deadline.

The following tables describe the Commission's minimum requirements for each category.

## Table 9A: General Requirements for All Inactive Wells

| | |
|---|---|
| Annual Inspection | Annual inspections include the requirements from the following sections:<br>• Visual Inspection<br>• Wellhead maintenance<br>• Surface casing vent flow (if applicable)<br>• Lease maintenance |
| Wellheads | Unperforated wells may use a welded steel plate atop the production casing stub. The plate must provide access to the wellbore for pressure measurement. All other wells must use standard wellheads as described in Enform's IRP Volume #2 (Completing and Servicing Critical Sour Wells) and IRP Volume #5 (Minimum Wellhead Requirements) |
| Wellhead Maintenance | There shall be no wellhead leaks.<br>Pressure recording must be taken from all annuli and production conduit.<br>Bullplugs or blind flanges with needle valves must be installed on all outlets except the surface casing vent.<br>The surface casing vent valve must be open and the surface casing vent unobstructed unless otherwise exempted by an official.<br>All valves must be chained and locked or valve handles must be removed.<br>The flowline must be disconnected or isolated from the wellhead. Isolation does not include a valve.<br>Polish rod removal is not required to suspend low risk oil wells as long as the polish rod remains connected to the pump jack. |
| Pressure testing seals | Low Risk and Medium Risk wells, do not require seals to be pressure tested if integrity can be proven. Criteria for proving integrity are:<br>• The well does not have a Surface Casing Vent Flow<br>OR<br>• If a positive pressure test is achieved on the casing string of which the seals are isolating<br>AND<br>• There is no evidence of failed seals based on the pressure in the intermediate casing string (if applicable) |

| | |
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| | Must indicate the method of confirming seal integrity on suspension report.<br><br>For wellheads that do not have adequate test ports, pressure tests may be omitted and visual observation for leaks is acceptable. An explanatory note must be included on the well suspension report.<br><br>High risk wells must pressure test the seals. |
| Surface Casing Vent Flows and Gas Migration | Surface casing vent flows and gas migration occurrences are to be managed and reported in accordance with Commission requirements. See Sections 9.7.3 through 9.7.5 (surface casing vent flow) and 9.7.6 (gas migration) of this manual for more information. |
| Lease Maintenance | A sign stating the well's surface location, current permit holder, the current permit holder's emergency contact number and appropriate warning symbols as defined in Section 15 of the Drilling and Production Regulation must be in place.<br><br>An area of 10 metres radius around the wellhead must be maintained to prevent brush from growing and causing a fire hazard.<br><br>Noxious weeds must be controlled.<br><br>Hazards associated with, but not limited to, pits, rat hole and storage materials, must be limited. |
| Visual Inspection | A visual inspection of the lease and wellhead must be conducted at least yearly to observe for wellhead integrity, noxious weeds and other hazards.<br><br>For wells with helicopter access (limited year-round access), the visual inspection frequency is the pressure testing / monitoring frequency. |
| Reporting | A Completion Report and a Well Suspension/Inspection form must be submitted to the Commission within 30 days of the completion of operations.<br><br>Records of inspections must be maintained on file and if requested, be made available to the Commission for review. |
| Downhole Abandoned | If all zones in a non-special sour well are abandoned and the well has not yet been surface abandoned, the well shall be categorized as "Low Risk - All cased wells (no perforations or open hole)". |
| Special Sour and Acid Gas Disposal | For classification criteria for special sour wells, see section 8.4.9 of this manual.<br><br>For re-classification and other information see section 9.4 of this manual.<br><br>Before suspension is considered, see Directive 20 Level-A requirements. |

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| | It is preferred to conduct a zonal abandonment rather than a suspension.<br>If a zone is deemed at capacity, the well should be abandoned. |

## Table 9B: Requirements Specific to Inactive High Risk Wells

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|---|---|---|
| Well Types | Type 1: Special sour wells[1].<br>Type 2: Acid gas disposal wells. | |
| Suspension Options | Option A | Option B |
| Downhole Requirements | Bridge plug or packer and tubing plug. | Bridge plug capped with 8 m lineal of cement. |
| Pressure Testing / Monitoring / Servicing Requirements | Pressure test both tubing and annulus to 7 MPa for 10 minutes.<br>Service and pressure test wellhead sealing elements. | Pressure test the casing to 7 MPa for 10 minutes.<br>Service and pressure test wellhead sealing elements (if applicable). |
| Pressure Testing / Monitoring / Servicing Frequency | At the time of suspension and then annually. | At the time of suspension and then every 5 years. |
| Wellbore Fluid | Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid. | Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid. |

[1] If applicable, install a bridge plug or packer and tubing plug within 100 metres of the liner top on uncompleted special sour wells. If this option is used, ensure the plug is placed within zone or 15 meters or perforations. This Commission encourages Permit Holders to review AER Directive 20 prior to suspending a Level-A well.

## Table 9C: Requirements Specific to Inactive Medium Risk Wells

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|---|---|---|---|
| Well Types | Type 1: Medium risk gas wells (see Appendix C for more information).<br>Type 2: Non-flowing oil wells ≥ 5% $H_2S$.<br>Type 3: Flowing oil wells[2].<br>Type 4: All injection and disposal wells except for acid gas disposal wells.<br>Type 6: Completed low risk wells that have been inactive or suspended for at least 10 consecutive years.<br>Type 7: All non-special sour cased wells that have been inactive or suspended for at least 10 consecutive years. | | |
| Suspension Options | Option A (All types) | Option B (All types) | Option C (type 7 only) |
| Downhole / Wellhead Requirements | Packer and tubing plug. | Bridge plug. | N/A |
| Pressure Testing / Monitoring / Servicing Requirements | Pressure test both the tubing and annulus to 7 MPa for 10 minutes.<br>Service wellhead. | Pressure test the casing to 7 MPa for 10 minutes.<br>Service wellhead. | Pressure test the casing to 7 MPa for 10 minutes.<br>Service wellhead. |
| Pressure Testing / Monitoring / Servicing Frequency | At the time of suspension and then every 3 years. | At the time of suspension and then every 5 years. | At the time of suspension and then every 5 years. |
| Wellbore Fluid | Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze | Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected | Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be |

[2] Flowing oil wells are oil wells **with** sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid.

| | | | |
|---|---|---|---|
| | protected by the use of a non-freezing fluid. | by the use of a non-freezing fluid. | freeze protected by the use of a non-freezing fluid. |

## Table 9D: Requirements Specific to Inactive Low Risk Wells

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| Well Types | Type 1: All non-special sour cased wells (no perforations or open hole sections).<br>Type 2: Low risk gas wells (see Appendix D of this manual).<br>Type 3: Water source wells.<br>Type 5: Non-flowing[3] oil wells < 50 mol/kmol $H_2S$. | |
| Suspension Options | Option A<br>(Types 2,3 and 5 only) | Option B<br>(Type 1 only) |
| Downhole Requirements | None. | None. |
| Pressure Testing / Monitoring / Servicing Requirements | Read and record shut-in tubing pressure (if applicable) and shut-in casing pressure.<br>Service wellhead. | Pressure test casing to 7 MPa for 10 minutes.<br>Service wellhead. |
| Pressure Testing / Monitoring / Servicing Frequency | When applicable. | At the time of suspension, at time of re-work, or abandonment, and when otherwise applicable. |
| Wellbore Fluid | None. | Wellbore must be filled with non-saline water or corrosion inhibited water. A minimum of the top 2 m must be freeze protected by the use of a non-freezing fluid. |

[3] Non-flowing oil wells are oil wells **without** sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid. Removal of polish rods is not required to suspend low-risk oil wells as long as the polish rod remains connected to the pump jack.

### 9.3.3 Packer Testing

Wells requiring installation and yearly testing of a production packer are exempt from the testing requirements if the well is suspended in accordance with the Drilling and Production Regulation. Information on packer isolation testing procedures is available in the Commission's Water Service Wells Summary Information document.

### 9.3.4 Long Term Inactive Wells

All completed low-risk wells must meet medium risk suspension requirements after being inactive for 10 consecutive years.

### 9.3.5 Reactivating Suspended Wells

The following procedures should be followed for the reactivation of a suspended well.

- All Wells:
  - Inspect, service and pressure test the wellhead.
  - Inspect and service control systems and lease facilities.
- Low Risk Type 1, Medium and High-Risk Wells:
  - Pressure test the casing to 7 MPa for 10 minutes (if applicable). If the test fails, investigate and repair the problem.
  - Pressure test the tubing (if present) to 7 MPa for 10 minutes. If the test fails, investigate and repair the problem.

#### Reactivating Suspended Wells to Water Source Wells

Permit amendments are required for converting an existing suspended well into a water source well.  Specific requirements are described in the Commission's Supplementary Information for Water Source Wells document.

## 9.4 Information and Reporting Requirements

### 9.4.1 Commission Reporting

#### Well Suspensions

A Well Suspension / Inspection Report must be submitted to the Commission's, Drilling and Production Department within 30 days of suspension of a well. The completed suspension report must be submitted through the eSubmission portal.

All downhole activities to plug and suspend are considered Workover operations and must be submitted to the Commission in a Completion/Workover Report. Suspensions are to be reported as Workovers on report cover pages and in Notices of Operation. Refer to the Well Data Submission Requirements Manual for further information.

#### Reactivations

Submission of a reactivation report is not required. Reactivations are identified by alternate means (i.e. spud date, production reporting).

#### Inspections

The completed inspection report must be submitted through the eSubmission portal. For more information regarding inspection frequency, refer to Section 9.3.2 of this manual.

## 9.5 Well Abandonment

Notification or approval is not required prior to conducting open hole plugbacks or abandonments.

Drilling wells that are downhole, but not surface abandoned at the time of rig release, are not considered abandoned. An abandonment notification and abandonment report must be submitted to the Commission at the time of surface abandonment as outlined below for the well status to be changed to abandoned.

## 9.5.1 Abandonment Notification

Notification is required 7 days prior to conducting all other well abandonments; however the notification requirement may be waived on a case by case basis. An abandonment program must be included with the notification.

## 9.5.2 Abandonment Procedures

Wells must be abandoned in a manner to ensure:

- Adequate hydraulic isolation between porous zones.
- Fluids will not leak from the well.
- Excessive pressure will not build up in any portion of the well.
- Long-term integrity of the wellbore is maintained.

Permit holders are expected to conduct abandonments and plugbacks in accordance with the AER Directive 20. If there is any doubt about the adequacy of a plugging or abandonment program, discuss the abandonment plans with the Commission. Failure to adequately plug or abandon a well may result in an order for remedial work.

Abandonment reports may be submitted using a Completion/Workover Report Form.

In cases where a well was cut and capped, but not reported to the Commission at the time the work was completed, the Commission will accept the following as evidence of cut and cap:

- A photograph of the signpost (grave marker) and wellsite. The signpost must contain adequate identifying information.
- Copies of invoices / welder's tickets for the work.

If the above materials are unavailable, excavate and photograph the casing stub.

# 9.6 Well Servicing Equipment and Procedures

## 9.6.1 Blowout Prevention

The following section outlines blowout prevention standards that a permit holder should follow to comply with the requirements of Part 4, Division 2 of the Drilling and Production Regulation. It is the responsibility of the permit holder to ensure that blowout prevention equipment and procedures are adequate.

A permit holder may use alternate blowout prevention equipment and techniques if they can demonstrate by means of a detailed engineering analysis that the alternate equipment or techniques are adequate as required by Section 16(1) of the Drilling and Production Regulation.

## 9.6.2 BOP Equipment Classes

For the purposes of well servicing, blowout prevention equipment classes are as follows:

- Class A equipment is required for a well where the minimum pressure rating of the production casing flange is less than or equal to 21,000 kilopascals (kPa) and the hydrogen sulphide content in a representative sample of the gas is less than one mol per cent.
- Class B equipment is required for a well where the minimum pressure rating of the production casing flange is:
  - Greater than 21,000 kPa.
  - Less than or equal to 21,000 kPa and the hydrogen sulphide content in a representative sample of the gas is one mol per cent or greater.
- Class C equipment is required for a special sour well (see IRP #2).

- Minimum stack components shall conform to the BOP stack configuration as shown in Appendix B of this manual.
- Minimum manifold design shall conform to a Class B manifold.
- Shear rams are required
- All metallic BOP components which may be exposed to sour effluent must be certified as being manufactured from materials meeting the requirements of NACE MR-01-75.
- Flanged BOP working spools with two flanged side outlets are required on critical sour wells.
- Working spool outlets must include full opening gate valves to serve as primary control. The kill side shall include a primary valve and a check valve, while the bleed off line shall have a primary and a secondary (back-up) valve. The valves shall be rated to a working pressure equal to or greater than the BOP.

### 9.6.3 General

At all times during well servicing, the well must be under control, adequate blowout prevention equipment must be installed and must be able to shut off flow from the well regardless of the type or diameter of tools or equipment in the well.

The blowout prevention equipment must have a pressure rating equal to or greater than the pressure rating of the production casing flange or the formation pressure, whichever is the lesser.

Hydraulic ram type blowout preventers which are not equipped with an automatic ram locking device must have hand wheels available.

An accurate pressure gauge to determine the well annulus pressure during a well shut-in must be either installed or readily accessible for installation.

A service rig used at the well site must have an operable horn on the drilling control panel for sounding alerts.

A sour service separator and flare system, including appropriate manifolding, must be used to process sour well effluent.

The well control system must be adequately illuminated.

## 9.6.4 Accumulator systems

All blowout preventers must be hydraulically operated and connected to an accumulator system.

The accumulator system must be installed and operated in accordance with the manufacturer's specifications. The system must be:

- Connected to the blowout preventers with lines of working pressure equal to the working pressure of the system, and within seven metres of the well, the lines must be of steel construction unless completely sheathed with adequate fire resistant sleeving.
- Capable of providing, without recharging, fluid of sufficient volume and pressure to effect full closure of all preventers, and to retain a pressure of 8,400 kPa on the accumulator system.
- Recharged by a pressure controlled pump capable of recovering the accumulator pressure drop resulting from full closure of all preventers within 5 minutes.
- Capable of closing any ram type preventer within 30 seconds.
- Capable of closing the annular preventer within 60 seconds.
- Equipped with readily accessible fittings and gauges to determine the pre-charge pressure.
- Equipped with a check valve between the accumulator recharge pump and the accumulator.
- Connected to a nitrogen supply capable of closing all blowout preventers installed on the well.

The accumulator nitrogen supply must:

- Be capable of providing sufficient volume and pressure to fully close all preventers and to retain a minimum pressure of 8,400 kPa.
- Have a gauge installed, or readily available for installation, to determine the pressure of each nitrogen container.

### 9.6.5 Requirements Specific to Class A Systems

Class A blowout prevention system:

- May utilize the rig hydraulic system to recharge the accumulator.
- Must have operating controls for each preventer in a readily accessible location near the operator's position and an additional set of controls located a minimum of 7 metres from the well.

### 9.6.6 Requirements Specific to Class B and C Systems

Class B and Class C blowout prevention system must have:

- An independent accumulator system with operating controls for each preventer located at least 25 metres from the well, shielded or housed to protect the operator from flow from the well.
- An additional set of controls in a readily accessible location near the operator's position.
- Working spools with flanged outlets.

Refer to IRP#2 for further information.

### 9.6.7 Flow Line Requirements

The following requirements do not apply to snubbing units and service rigs completing rod jobs. A blowout prevention system must have two lines, one for bleeding off pressure and one for killing the well, which must:

- Be either steel or flexible sheathed hose to provide adequate fire resistant rating.
- Be valved and have a working pressure equal to or greater than that required for the blowout prevention equipment.
- Have one line connected to the rig pump and one line connected to the tank.
- Be at least 50 mm nominal diameter.
- Be securely tied down.

### 9.6.8 Stabbing Valve

A full opening ball valve (stabbing valve) which can be attached to the tubing or other pipe in the well must:

- Be ready for use and located in a readily accessible location on the service rig.
- Be maintained in the open position.
- Have an internal diameter equal to or greater than the smallest restriction inside the tubing or casing.
- Be kept clean and ice free.

### 9.6.9 Blowout Prevention Manifold

The blowout prevention system must include a manifold that:

- Has a working pressure greater than or equal to that of the blowout prevention system installed on the well
- Contains a check valve to prevent flow from well to rig pump
- Contains a pressure relief valve upstream of the check valve
- Is equipped with an accurate pressure gauge which shall be either installed or readily accessible for installation

## 9.6.10 Testing of Blowout Prevention Equipment

Before commencing servicing operations at a well, a 10-minute pressure test must be conducted on each ram preventer to 1,400 kPa, prior to the tests described as follows:

- Each ram preventer, the full opening safety valve and the connection between the stack and the wellhead, tested to the wellhead pressure rating or the formation pressure, whichever is less.
- Each annular preventer to 7,000 kilopascals or the formation pressure, whichever is less. For an annular type blowout preventer, all mechanical and pressure tests must be conducted with pipe in the blowout preventer.

All blowout prevention equipment, except for shear rams on special sour wells, must be mechanically tested daily, if operationally safe to do so; any equipment found defective must be made serviceable before operations are resumed.

A pressure test is considered a pass if the pressure decrease is less than 10% over the 10 minute test.

All tests must be reported in the servicing log book and in the case of a pressure test, the report must state the blowout preventer tested, the test duration and the test pressure observed at the start and finish of each test.

At least once every three years, all blowout preventers must be shop serviced and shop tested to their working pressure and the test data and the maintenance performed must be recorded and made available to an official on request.

## 9.6.11 Special Sour Wells

Refer to Enform's IRP Volume #2: Completing and Servicing Critical Sour Wells for detailed information.

### 9.6.12 Slickline, Snubbing and Coil Tubing Operations

- Refer to Enform's IRP Volume #13: Slickline Operations.
- Refer to Enform's IRP Volume #15: Snubbing Operations.
- Refer to Enform's IRP Volume #21: Coiled Tubing Operations.

### 9.6.13 Hammer Unions

Hammer unions should not be used in the manifold shack or under the rig substructure.

### 9.6.14 Personnel

Section 13 of the Drilling and Production Regulation advises on ensuring a sufficient number of trained and competent individuals carry out all well operations safely and without causing pollution. The following people must possess a valid Well Service Blowout Prevention Certificate, issued by Enform:

- The driller on tour.
- The rig manager (tool push).
- The permit holder's representative.

If gas containing $H_2S$ is expected, every crew member must be trained in $H_2S$ safety.

Blowout prevention drills should be performed by each rig crew every seven days or once per well, whichever is more frequent. Blowout prevention drills should be recorded in the servicing log book.

Evidence of the qualifications of any person referred to in this section must be made available to an official on request.

The rig crew must have an adequate understanding of, and be able to operate, the blowout prevention equipment and, when requested by an official and if it is safe to do so, the contractor or rig crew must:

- Test the operation and effectiveness of the blowout prevention equipment.
- Perform a blowout prevention drill in accordance with the Well Control Procedure placard issued by the Canadian Association of Oilwell Drilling Contractors (CAODC) or as outlined by the Enform Blowout Prevention Manual.

Refer to Enform's IRP Volume #7: Standards for Wellsite Supervision of Drilling, Completions and Workovers for more information.

## 9.6.15 Fire Precautions and Equipment Spacing

Refer to Sections 45 and 47 of the Drilling and Production Regulation.

### Engines

Permit holders must ensure that, if engines are located at a wellsite, suitable safeguards are installed and tested to prevent a fire or explosion in the event of a release of flammable liquids or ignitable vapours.

For engines located within 25 metres of a well, petroleum storage tank or other unprotected source of ignitable vapours, the Commission recommends that:

- The engine exhaust pipe is insulated or cooled to prevent ignition in the event that flammable material contacts the exhaust pipe.
- The exhaust pipe is directed away from the well or source of ignitable vapours.
- The exhaust manifold is sufficiently shielded to prevent contact with flammable materials.

For diesel engines located within 25 metres of a well, the Commission recommends that one of the following devices be installed:

- A positive air shutoff valve, equipped with a readily accessible control.

- A system for injecting inert gas into the engine's cylinders, equipped with a readily accessible control.
- A suitable duct so that air for the engine is obtained at least 25 metres from the well.

Permit holders must also ensure compliance with the requirements in Work SafeBC's (Section 23.8) Occupational Health and Safety Regulation.

## Fuel

Gasoline or liquid fuel, except for fuel in tanks that are connected to operating equipment, must not be stored within 25 metres of a well and drainage must be away from the wellhead.

## Smoking

Smoking is prohibited within 25 metres of a well.

## Recommended Spacing Distances

Ensure appropriate spacing is maintained between potential sources of flammable liquids or ignitable vapours and ignition sources. Table 9E provides a matrix for recommended spacing distances. All fires must be sufficiently safeguarded and all vessels and equipment from which ignitable vapours may issue must be safely vented.

Flares and incinerators must be located at least 80 metres from any public road, utility, building, installation, works, place of public concourse or reservation for national defence.

## Table 9E: Recommended Spacing Distances

| | Wellhead | Flare Or Incinerator | Boiler, Steam Generating Equipment, Teg* | Produced Water Tank | Other Sources Of Ignitable Vapours | Separator | Flame Type Equipment | Produced Flammable Liquids Crude Oil & Condensate Tanks |
|---|---|---|---|---|---|---|---|---|
| Wellhead | | 50 | 25 | Ns | Ns | Ns | 25* | 50 |
| Flare Or Incinerator | 50 | | Ns | 25 | 25 | 25 | 25 | 50 |
| Boiler, Steam Generating Equipment, Teg* | 25 | Ns | | 25 | 25 | 25 | 25 | 25 |
| Produced Water Tank | Ns | 25 | 25 | | Ns | Ns | 25* | Ns |
| Other Sources Of Ignitable Vapours | Ns | 25 | 25 | Ns | | Ns | 25* | Ns |
| Separator | Ns | 25 | 25 | Ns | Ns | | 25* | Ns** |
| Flame Type Equipment | 25* | 25 | 25 | 25* | 25* | 25* | T | 25* |
| Produced Flammable Liquids Crude Oil & Condensate Tanks | 50 | 50 | 25 | Ns | Ns | Ns** | 25* | |

All distances are in metres (M). * 25 m without flame arrestors, not specified with flame arrestors. ** Separator cannot be in the same dyke. T treaters should be at least 5 m (shell to shell) from other treaters.

Note: A) boilers etc. includes steam generating equipment, electric generators and teg units. B) Other sources of ignitable vapours include compressors. C) Flame type equipment includes: treaters, reboilers and line heaters. D) All electrical installations must conform to the Canadian Electrical Code.

## Flare Stacks

A sufficient area beneath and around flare stacks must be cleared of flammable materials and vegetation.

The recommended blackened area beneath a flare stack is 1.5 times the stack height to a minimum of 10 metres in cultivated areas and 30 metres in forested areas, unless conditions support a lesser distance.

The Commission recognizes that a lesser area may be justified depending on the circumstances. It is the responsibility of the permit holder to maintain a sufficient area, given the location and the conditions under which flaring will or may occur.

Flare blackened areas must be maintained within permissioned land area. If new area is required to accommodate the blackened area, an amendment to the well/facility area is required.

### Explosives

Explosives must be stored in properly constructed magazines and be located a minimum of 150 metres from any well servicing operation.

## 9.6.16 Inter-Wellbore Communications

Inter-wellbore communication may occur as a fluid and/or pressure communication event at an offset well resulting from fracture stimulation on a subject well. Communication levels include:

- Incident level communication is a communication resulting in a spill, equipment overpressure, equipment damage, injury or a drilling kick.
- Event level communication is any communications not at the incident level.

Permit holders are obligated to manage the risks of inter-wellbore communication between the subject well and an offset well. Document hydraulic fracturing programs and include the following elements:

- Identify all offset wells that could be affected.
- Conduct a risk assessment of the identified offset wells.
- Develop a well control plan for all offset wells that are at risk.
- Modify the hydraulic fracturing program if risks cannot be mitigated.

Subject well permit holder must notify a permit holder of an at-risk offset well of a planned hydraulic fracturing program and make all reasonable efforts to develop a mutually-agreeable well control plan. The subject well permit holder must maintain a copy of the at-risk well control plan for the duration of hydraulic fracturing operations.

The permit holder of an at-risk offset well, upon receiving notification of a planned hydraulic fracturing program, is expected to engage and work cooperatively with the subject well permit holder in development of well control plans.

Report all fracture communication events using the Commission's Inter-Wellbore Communication Report Form (located on the Commission's Wells Documentation web page) and follow Enform's IRP Volume #24: Fracture Stimulation (Draft) for specific methodology and procedures regarding the inter-wellbore communication management process.

All fracture communication incidents must also be reported in accordance with the Commission's Incident Reporting Instructions and Guidelines.

## 9.7 Environmental Considerations

The environmental considerations section outlines and explains the regulatory requirements for testing, repairing and reporting environmental impacts: hydraulic fracturing, seismic activity, surface case venting flows, gas migration, casing leaks and failures, noise, fluid storage and spills.

In addition, refer to the Flaring and Venting Reduction Guideline for detailed guidance.

### 9.7.1 Hydraulic Fracturing Fluid Report

Section 37 of the Drilling and Production Regulation states that permit holders carrying out hydraulic fracturing operations must maintain detailed records of fracture fluid composition, and submit records to the Commission within 30 days of well completion. Hydraulic fracture fluid reports are submitted to the Commission via Kermit. More information on hydraulic fracture fluid reporting is available in the Fracture Fluid Disclosure Manual.

### 9.7.2 Seismic Activity

Infrastructure must be built to withstand the effects of the elements or seismic disturbance. Requirements to monitor, report and address seismic disturbances must be followed.

Permit conditions may be employed to regulate induced seismicity. During fracturing operations, permit holders must contact the Commission Emergency Contact at 1-800-663-3456 in the following seismic event:

- Recorded by the permit holder or any source available to the permit holder as being magnitude 4.0 or greater and within a three kilometre radius of the drilling pad.
- Felt on the surface within a three kilometre radius of the drilling pad.

In the event of a well pad is responsible for a seismic event, the permit holder will suspend fracturing operations on the well immediately. The seismic event may be identified by either the permit holder or the Commission as described above.

Suspended fracturing operations may be continued if: Permit holder presents to the Commission a plan for mitigation aimed at reducing the seismicity or eliminating well operations related to the induced seismicity.

- Commission is satisfied with the plan.
- Permit holder implements the plan.

The Commission tracks northeast B.C. seismic events and compares these seismic events alongside the locations of oil and gas permit holders. Further information and recommendations from the Commission's investigation into seismic activity is detailed in the Investigation of Observed Seismicity in the Montney Basin and the Investigation of Observed Seismicity in the Horn River Basin.

## 9.7.3 Surface Casing Vent Flow

Permit holders must carry out surface casing vent flow activities, checks and tests, repairs where applicable and as detailed in this section and according to Section 41 of the Drilling and Production Regulation.

Surface Casing Vent Flow (SCVF) means:

- The flow of gas and/or liquid from the surface casing/ casing annulus.

Serious Surface Casing Vent Flow means:

- Vent flows with hydrogen sulphide ($H_2S$) present.
- Vent flow with a stabilized gas flow rate equal to or greater than 300 cubic metres per day ($m^3/d$).
- Vent flow with a surface casing vent stabilized shut-in pressure greater than one half the formation leak-off pressure at the surface casing shoe or 11 kPa/m times the surface casing setting depth.
- Hydrocarbon liquid (oil) vent flow.
- Vent flow due to wellhead seal failures or casing failure.
- Water vent flow if the water contains substances that could cause soil or groundwater contamination.
- Vent flow where any usable water zone is not covered by cemented casing.
- Other vent flow constituting a fire, public safety, or environmental hazard.

### Checking for Surface Casing Vent Flows

In accordance with Section 41 (2) of the Drilling and Production Regulation, a permit holder must check each well for evidence of a surface casing vent flow:

(a) immediately after initial completion or any recompletion of the well,

(b) at the time of rig release,

(c) as routine maintenance throughout the life of the well,

(d) before suspension of the well,

(e) before abandoning the well, and

(f) before applying for a transfer of the well permit.

Visual observation is sufficient to confirm the presence of a liquid SCVF. The presence of H2S in a SCVF can be confirmed by the use of a personal monitor, onsite H2S tests, or other methods as appropriate.

A 10-minute bubble test is the minimum acceptable test for the presence of a surface casing vent flow of sweet gas. The recommended procedure is as follows:

- Bubble Test Equipment:
  - Container of water (from 500 ml to 1L).
  - Pipe fittings, small hose (minimum 6mm), or other equipment necessary to direct gas flow from vent downward in the water container.
- Bubble Test Procedure:
  - Ensure no gas leaks at fittings and welds.
  - Ensure there is no $H_2S$ present.
  - Ensure all valves in the vent line are open.
  - If necessary, connect test fittings to the vent so gas flow can be directed into the container of water.
  - Immerse vent or hose a maximum of 2.5 cm below the water surface.
  - Observe for 10 minutes. Note any gas flow (for example, bubbles) which must be recorded as a positive vent flow.
  - Record observations.

## Testing and Reporting Surface Casing Vent Flows

Serious surface casing vent flows present a safety or environmental hazard and must be reported to the Commission immediately.

On discovery of a surface casing vent flow that does not present an immediate safety or environmental hazard, a well permit holder must test the surface casing vent flow rate and buildup pressure, and report the surface casing vent flow test results to the Commission within 30 days of the discovery of the surface casing vent flow.

Following discovery and initial reporting, permit holders should perform annual surface casing vent flow tests for a minimum of five years. The permit holder may select appropriate yearly testing measures, however, the Commission may order specific test measures for surface casing vent flows of particular concern.

In the event a significant change to a previously-identified SCVF is observed, permit holders should report their findings to the Commission. Examples of a significant change are:

(a) from no vent flow to non-serious vent flow or serious vent flow,

(b) from non-serious vent flow to serious vent flow, or vice-versa,

(c) from non-serious vent flow or serious vent flow to no vent flow

The results of SCVF tests required as part of a Commission inspection must be reported.

The Commission recommends that permit holders report all surface casing vent flow test results. Non-reported test results must be maintained on file and provided to the Commission on request.

All reporting of SCVF test results must be done via the Commission's eSubmission portal.

## Measuring Flowrate

Once a positive vent flow is detected, the flow rate and stabilized shut in pressures must be recorded. To measure venting gas volumes, a positive displacement gas meter, turbine meter or an orifice well tester may be used. Equipment selection should be based on previous observations indicating what flow rate and pressure range can be expected. A positive displacement meter will be necessary to measure low volumes accurately. An orifice well tester, with proper orifice plate, may provide satisfactory measurements if the 24 hour shut in pressure is 200 kPa or greater and builds quickly.

Install and use the equipment according to manufacturer's instructions:

- Do not exceed the pressure/volume range of the equipment.
- Ensure there are no leaks.

## Measuring Buildup Pressure

To determine the maximum shut-in surface casing pressure the following method can be used.

Pressure Buildup Required Equipment includes:

- Pressure gauge or single pen static pressure recorder with 24 hour chart.
- Dead weight pressure gauge.
- Electronic pressure recorder.

A pressure relief valve, calibrated to release the pressure if it was built to its maximum allowable surface pressure, should be installed on the surface casing vent while measuring the buildup pressure. If it is anticipated the maximum allowable shut in pressure will be exceeded, a suitable recording device must be used in order to capture the rise and decline of pressure (i.e. electronic recorder).

Pressure Buildup Testing Procedure:

- Install pressure recorder and pressure relief valve.
- Ensure that there are no gas leaks at fittings and welds.
- If a chart is used, note the chart reading 24 hours later. If pressure has not stabilized, it may be necessary to change the chart in order to cover a longer time period in order to achieve a maximum shut-in pressure.

- Monitor the readings to determine when a stabilized maximum pressure is obtained and record this value.

## 9.7.4 Surface Casing Vent Flow Repairs

### Non-Serious Repair

Remedial repair may be deferred until well abandonment for non-serious surface casing vent flows.

In an effort to minimize the amount of venting from a non-serious surface casing vent flow, the permit holder may consider the installation of a burst plate or pressure safety valve (PSV). The permit holder must obtain an exemption to Section 18(9)(a) of the Drilling and Production Regulation to allow the installation of a burst plate or pressure safety valve.

Non-serious surface casing vent flows must be repaired at the time of well abandonment.

### Repair of a Serious Surface Casing Vent Flow

The permit holder of a well determined to have a serious surface casing vent flow should contact the Commission as soon as possible to discuss repair or management requirements.

## 9.7.5 Surface Casing Vent Flow Production

If the permit holder wishes to explore the option of producing the surface casing vent flow, an application must be made to the Drilling and Production Department to obtain an exemption to Section 18(9)(a) of the Drilling and Production Regulation. Requests will be considered if:

- The source depth and formation of origin has been clearly identified.

- The permit holder owns the mineral rights to produce the source formation.
- The cemented portion of the surface casing or the next casing string covers the deepest known usable groundwater.
- The flow has been analyzed and determined to be sweet (0 per cent $H_2S$).

The Commission may rescind the approval to produce from the surface casing vent and may require the surface casing vent flow to be repaired at any time if the Commission determines a safety or environmental hazard exists.

## 9.7.6 Gas Migration Reporting, Testing and Risk Assessment

"Gas migration" means a flow of gas outside of the surface casing of a well.

### Gas Migration Reporting

In accordance with Section 41 (4.1) of the Drilling and Production Regulation DPR), upon the discovery of an occurrence of gas migration, a permit holder must notify the Commission of the gas migration within 72 hours by the submission of a completed gas migration report submitted via the eSubmission portal.

Notification is required:

- if gas migration is visible as bubbles in water at the wellhead.
- If gas migration is confirmed by any field testing.

Field testing at the ground surface outside the surface casing to confirm the presence or absence of gas should be conducted if:

- there is any visual, auditory, olfactory, or other evidence of possible gas migration, or
- issues with well drilling and completion, or with well condition, indicate the potential for gas migration.

## Gas Migration Risk Assessment

A risk assessment report must be submitted within 90 days of the Commission's notification of gas migration, unless an alternate submission schedule is authorized by the Commission. Based on review of the report, the Commission will provide a written response confirming the requirement to submit a risk assessment report in accordance with Section 41(4.1) of the DPR has been met, and specifying any requirements for further investigation, monitoring, mitigation, and/or reporting.

The risk assessment must be completed under the direction of a Qualified Professional. A Qualified Professional must possess an appropriate combination of formal education, knowledge, skills, and experience to conduct a technically sound and rational assessment for the area of practice, and be familiar with applicable regulations, standards, policies, protocols and guidelines.

The risk assessment and risk assessment report must include the following unless previously submitted to the Commission.

- Documentation of Well and Site Information, including:
  - A summary of well construction details and relevant well history.
  - Evidence of gas migration (e.g., bubbles, stressed vegetation).
  - Description of site geographic location, site facilities and structures, topographic information and features, land surface conditions (vegetation, land clearing), and surrounding land use (including protected areas and parkland).
  - Supporting maps and site plans.
- Documentation of Field Investigation and Results, including:
  - The completion of a Shallow Gas Survey as described in this manual
  - The collection and analysis of one or more gas samples (e.g., from surface casing vent, area(s) of gas migration, and from the well) for the purposes of evaluating the source of the gas. Samples must be submitted to a qualified laboratory for analysis of hydrocarbons, $H_2S$, and isotopic analysis. Laboratory analytical reports must be included with the report.
  - Measurement of gas flow rates including surface casing vent flow, and gas migration between surface casing and conductor casing or elsewhere, if possible.

- Results of any groundwater monitoring that has been conducted at the wellsite with information on well locations, geological conditions, and well construction specifications.
- Measurement of gas concentration or LEL's at ground level, in the same pattern as the Shallow Gas Survey.

- An assessment of the source and cause of gas migration, including:
  - A description of the interpreted source of gas migration and known or suspected cause of gas migration based on well information and field testing.
- Identification of Potential Human and Environmental Receptors, including:
  - Documentation of desktop information for a 2 km radius surrounding the well related to proximity to potential human or environmental receptors including: information for water supply wells, mapped aquifers, mapped capture zones (i.e., water well source areas), provincial observation wells, residential areas, public and protected areas, surface water bodies, Provincial water authorizations (e.g., water use approvals or licences), or other relevant information. The Commission's Groundwater Review Assistant (GWRA) should be used to compile desktop information and a copy of the GWRA output report shall be included with the Risk Assessment Report. Additional land use information may be compiled using iMapBC, Google Earth, and/or review of aerial photographs or imagery where available.
  - Documentation of a "windshield" field reconnaissance, conducted where practicable, to verify the desktop information related to land occupancy/use and the locations of water supply wells.
  - Supporting maps as appropriate.
- Assessment of Risk and Proposed Mitigation and Management Measures, including:
  - Tabulated risks using the BC OGC Risk Assessment Framework for Wellsites with Gas Migration (see Table 9F), which includes identification of hazards and assessment of potential safety, health, and environmental risks based on the compiled well, desktop, and field investigation information. A fillable form version of Table 9F can be found on the Commission's website.
  - Proposed mitigation and management measures for identified risks. These must include, where appropriate, gas migration repair measures, site

restoration measures, well abandonment plan, groundwater and/or soil quality assessment (installation of monitoring wells), long term monitoring of gas flow and extent of gas migration, air quality monitoring, enhancements to site security (e.g., fencing), any or other appropriate measures.

The proposed mitigation and management measures will be reviewed by the Commission.

# Table 9F: BC OGC Risk Assessment Framework for Wellsites with Gas Migration

[1]Risk rating must be supported by information documented in or appended to the Risk Assessment Report.
Risk rating may be updated following implementation of management, monitoring, mitigation, or further investigation.

**Well Authorization Number:** _____________ **Risk Assessment Report Date:** _______________

| Risk Category | Potential Hazard Description and Risk Rationale | Risk Rating Guidance | | | [1]Risk Rating and Proposed Management, Monitoring, Mitigation or Further Investigation |
|---|---|---|---|---|---|
| | | **Low** | **Moderate** | **High** | |
| General Public Safety | Identify potential public safety hazards within the lease area (site), including general hazards associated with infrastructure and potential confined space hazards, with consideration of the potential for unintentional or intentional public access. | No potential hazards identified | One or more potential site hazards identified **AND** low potential for public access to site | One or more potential site hazards identified **AND** reasonable potential for public access to site | |
| Fire or Explosion | Identify potential hazards based on shallow gas survey results with consideration of potential ignition sources. | Gas Concentrations < 100% LEL **OR** >100% LEL and access is restricted | Gas Concentrations > 100% LEL **AND** low potential for ignition source | Gas Concentrations > 100% LEL **AND** potential for ignition source | |
| Air Quality | Identify potential concerns related to air quality due to odour and $H_2S$ based on field observations or gas analysis, with consideration of potential human receptors. | No odour observed **AND** gas does not contain H2S | Odour is apparent **AND** members of the public are highly unlikely to be within 100 m of the site | Gas contains $H_2S$ **OR** odour is apparent and potential exists for members of the public to be within 100 m of the site | |
| Groundwater | Identify potential hazards to groundwater quality based gas analysis and the shallow gas survey results, with consideration of the potential for groundwater to reach potential human receptors. | Gas is not thermogenic **AND** gas migration does not extend off site | Gas is thermogenic **OR** gas is not thermogenic and shallow gas extends off site | Gas is thermogenic **AND** water wells, water intakes, or licensed springs are within 600 m of the well | |
| Surface Water and Riparian Areas | Identify potential hazards based on the gas analysis with consideration of the potential for groundwater discharge to surface water bodies/riparian areas. | Gas is not thermogenic **OR** gas is thermogenic with low potential for groundwater discharge to a riparian area or surface water body | Gas is thermogenic **AND** there is potential for groundwater discharge to a riparian area or surface water body | Gas migration flow rates could result in the accumulation of gas at surface water bodies or riparian areas on or off site | |

A fillable version of Table 9-F is available on the Commission's website.

## Shallow Gas Survey Procedure

The Commission requires testing to be carried out to identify the extent of gas migration in the shallow subsurface by completion of a shallow gas survey extending radially around the wellhead as follows.

- Required Equipment:
  - Bar or auger (64 mm or less in diameter) capable of penetrating a minimum of 50 cm.
  - Calibrated monitor or other instrument capable of detecting hydrocarbons at on per cent lower explosive limit (LEL).
  - Equipment or material to seal the hole at surface while soil gases are being evacuated from the soils through the instrument.
- Preparation for testing:

  Testing must be done in frost free months only and periods immediately after rainfall should be avoided. If contaminated soils are suspected across the survey area, the soil should be excavated and removed prior to testing. Instrument calibration must be performed.
- Sampling points:

  Two sampling points must be located within 30 cm of the wellbore on opposite sides. Additional sampling points must be placed at two meter intervals outward from the wellbore, every 90 degrees (centered at the wellbore), to a minimum radius of 6 m.

  If detectable gas is identified at a 6 m distance from the wellhead, the shallow gas survey must be extended by appropriate distance intervals over an area sufficient to delineate the extent of gas in the shallow subsurface.

  In addition to the above sampling locations, at least four additional point measurements should be made outside the four sides of a compacted well pad if the well pad could be considered to be a potential barrier to the efflux of gas at the ground surface.
- Test Procedure:
  - Insert auger or make a bar hole a minimum of 50 cm deep.
  - Isolate the hole from atmospheric contaminants.
  - Obtain sample a minimum of 30 cm into the hole, maintaining a seal at surface to prevent atmospheric gas and soil gas mixing.

- Withdraw soil gas sample. The volume, rate, etc., will depend on the instrumentation being used. Ensure that a sufficient sample is removed to purge lines and instrumentation.
- Purge instrument and lines prior to taking next measurement.
- Document preparation, procedures and results.

### 9.7.7 Casing Leaks and Failures

A permit holder must notify the Commission of any casing leak or casing failure as soon as possible. The leak or failure must be repaired within a reasonable time frame, giving consideration to the accessibility of the site and the seriousness of the leak or failure.

### 9.7.8 Noise

Section 40 of the Drilling & Production Regulation states:

- A permit holder must ensure operations at a well or facility for which the permit holder is responsible does not cause excessive noise.

Review Section 40 of the DPR and the Commission's British Columbia Noise Control Best Practices Guideline for an understanding of noise levels, requirements and suggested best practice standards. In addition, work with area residents to minimize noise impacts when undertaking construction, drilling, completions, and operations activities near populated areas.

### 9.7.9 Fluid Storage at Well Sites

Secondary containment of tanks associated with completions operations is generally not required. For extended, unmanned flowback operations requiring a facility permit, secondary containment in accordance with the National Fire Protection Agency's Flammable and Combustible Liquids Code (NFPA 30) is required.

The Commission's Management of Saline Fluid for Hydraulic Fracturing Guideline details the requirements and expectations for siting, design, construction, operation, and decommissioning of lined containment systems used for the storage of saline fluids.

The Management of Saline Fluid for Hydraulic Fracturing Guideline provides guidance for permit holders to demonstrate ongoing compliance with OGAA and EMA, and the regulations with respect to the storage of saline fluids.

## 9.8 Well Data Submission

### 9.8.1 Completion /Workover / Abandonment Report

The Completion / Workover / Abandonment Report is due within 30 days of the end of main operations. Refer to the Notice of Operation and Completion Report Reference Guide for a list of activities that require submission of a completion / Workover report.

For more information on operations not listed in the Notice of Operation and Completion Report Reference Guide, contact Drilling and Production by email at OGCDrilling.Production@bcogc.ca or phone 250-794-5258.

#### Required Information/Attachments to Completion/Workover Report

The Completion / Workover / Abandonment Report must include the following attachments:

- Chronological summary - either on this form if a short summary, or on separate enclosed page, list the major events in this completion report by date, such as perforations or frac port openings, stimulation operations, setting temporary or permanent plugs/zonal abandonments, milling operations, type of production string installed and flowing operations.

- Detailed completion/workover daily reports.
- Downhole schematic diagram.
- Completion/Workover Report Cover Page.
- Copy of the Notice of Operation.

The Completion / Workover Report cover page requires the following:

- Completion type: kind of completion done (such as, Open Hole well, Single if one zone capable of producing, Dual or Multi if 2 or more zones capable of producing separately, Commingled if two or more formations producing together).
- Completion activity: all operations performed within this completion report.
- Stimulation type: which achieved breakdown or well flow. If Acid Stimulation, state the acid volume pumped in the stimulation in cubic meters ($m^3$) and the maximum pressure used in the acid stimulation in kilopascals (kPa). If hydraulic fracturing conducted, submit Hydraulic fracture data in comma separated value (.csv) files through the eSubmisison portal.

  The Commission provides the following documents to guide the submission of comma separated value files for hydraulic fracture data:

  - Hydraulic Fracture Comma Separated Value (CSV) How-To Guide
- Flow summary (for each formation): the hydrogen sulphide ($H_2S$) per cent, oil rate, water rate, choke size or API gravity.
- Flow rate in $10^3m^3$/day.
- Flow pressure in kPa.
- Final flow date.
- Radioactive material used in the workover (such as frac sand). If used, attach documentation explaining the method of disposal or, if buried on site, attach sketch of location showing burial location and indicate depth of burial and volume of material.
- Results of work done and the outcome of the operation (such as, successful completion of the Montney; well on production; productivity increased; water flow successfully shut-off; well successfully suspended)

For the above example, the result would be, “Bluesky tested and suspended with BP”.

The Completion / Workover / Abandonment Report is submitted to the eSubmission portal within 30 days of the end of main operations.