Directive 013

Release date: December 6, 2018

Effective date: December 6, 2018

Replaces previous edition issued October 25, 2018

Suspension Requirements for Wells

Contents

1 Introduction

This directive sets out suspension requirements and reactivation requirements for wells as required under section 3.020 of the *Oil and Gas Conservation Rules* (*OGCR*).

1.1 What's New in This Edition

On October 25, 2018, the following changes were made:

- Section 3.2 was updated to give licensees an additional option when suspending and inspecting medium-risk type 6 wells based on an AER-approved closure plan. A closure plan is a proposal by a licensee to close oil and gas infrastructure, reducing the licensee's end-of-life obligations. For more information on closure plans, please contact us at WellOperations@aer.ca.
- Sections 3.1.1, 3.1.2, 3.2.1, and 3.3.1 were modified to better communicate the initial suspension and ongoing inspection requirements.

On December 6, 2018, further updates were made to the directive to replace references to the Digital Data Submission system with the more generic "designated information submission system." The *Directive 013* webpage on the AER website sets out the designated information submission systems relevant to this directive.

1.2 Definitions

An inactive well is defined as follows:

- Critical sour wells (perforated or not) that have not reported any type of volumetric activity (production, injection, or disposal) for six consecutive months
- All other wells that have not reported any type of volumetric activity (production, injection, or disposal) for 12 consecutive months

Critical sour wells are licensed as critical wells and defined under *Directive 056: Energy Development Applications and Schedules*.

Additional definitions are set out in appendix 2.

2 Suspension Requirements for All Wells

2.1 General Requirements

All inactive wells must be classified and properly suspended as defined in this directive. The licensee must complete the initial suspension and reporting requirements for all inactive wells within 12 months from the *Directive 013* inactive status date (as listed in the inactive well licence list on the designated information submission system). The *Directive 013* inactive status date is calculated based on the definition of the inactive well. If the well has never produced or has no volumetric activity reported on Petrinex, a final drill date is used as a last volumetric activity date when calculating *Directive 013* inactive status date. Flaring or venting is not considered to be a volumetric activity.

For inactive cavern wells, the licensee must submit a nonroutine application to WellOperations@aer.ca for the suspension of the well and cavern.

Observation wells are exempt from *Directive 013* requirements.

For wells to remain in compliance with this directive, the licensee must complete the ongoing well inspection requirements and report to the AER via the designated information submission system by the end of the calendar year in which the inspection due date is calculated. The inspection due date is calculated from the initial suspension date and based on the inspection frequency indicated for each risk class in section 3. The process for reporting and information required in the report is outlined in section 2.5.

Example

For a high-risk well (see section 3 for details on risk-based requirements): If the "*Directive 13* Inactive Status Date" is June 30, 2015, the licensee must complete the initial suspension and reporting by June 30, 2016. If the high-risk well is suspended with a packer and tubing plug, the inspection frequency is one year and the inspection due date is June 30, 2017. Therefore, the inspection requirements must be completed and reported in the designated information submission system by December 31, 2017.

Section 3 outlines the initial suspension requirements, ongoing inspection requirements, and frequency of inspections according to well risk category.

2.2 Changing Well Risk Category

Wells in a particular risk category may also be suspended in accordance with the requirements of any higher risk category; however, the well must meet the initial suspension and ongoing inspection requirements based on the higher risk category.

For wells with multiple zones,

- the well must be classified based on the highest-risk zone in the wellbore that has not been abandoned, in accordance with *Directive 020: Well Abandonment*; and
- if all zones are abandoned (and the well has not yet been surface abandoned), the shallowest completion must be used to classify the risk category for the well.

For the purpose of this directive, proper zonal abandonment of all completed intervals in accordance with *Directive 020* is an equivalent suspension method to a bridge plug for low- and medium-risk wells, and to a bridge plug capped with eight metres of cement for high-risk wells. All the ongoing inspection requirements and timelines must be met respectively.

For a well to move from the high-risk category to medium or low risk, the status of critical sour, class 1a well would have to be terminated. Until the status is terminated by the AER, the well will remain under the high-risk category.

To remove “Critical Sour” status, a declassification request must be sent to WellOperations@aer.ca in accordance with *Interim Directive 90-01: Completion and Servicing of Sour Wells,* section 5.2. If the approval is granted, the licensee would receive a declassification letter and the electronic record of the well will be updated to “Declassified Critical Sour.”

To remove an acid gas designation, either the scheme must be terminated or the well licence must be removed from the scheme. The licensee must submit a request in accordance with *Directive 065: Resources Applications for Oil and Gas Reservoirs*, providing all the supporting documentation to verify the reason for termination. Reasons could include the following:

- The licensee has never completed (perforated) the zone approved for acid gas injection.
- The licensee has never injected acid gas into the approved zone and there are no offset wells in the area that are injecting, or have injected acid gas into the same zone.
- The zone with acid gas was abandoned in accordance with level-A requirements of *Directive 020*.

If the *Directive 065* application is approved, the scheme approval is terminated, or the well licence is removed from the scheme, the well is no longer considered to be an acid gas well for the purpose of this directive.

Licensees requiring assistance regarding these requirements should contact the AER at WellOperations@aer.ca.

2.3 Surface and Wellhead Requirements

2.3.1 Surface Requirements

The licensee must

- immediately take reasonable steps to contain and clean up spills or releases in accordance with *OGCR* sections 8.050(1), (2), and (3);
- have appropriate signage at the well in accordance with *OGCR* section 6.020;
- have a 24-hour emergency telephone number posted in accordance with *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*;
- leave pumpjacks in a secure condition; and
- remove all debris from the site.

2.3.2 Wellhead Requirements

The licensee must

- ensure that there are no wellhead leaks;
- service and pressure test a wellhead, sealing elements at time of suspension and at each subsequent inspection;
- ensure that valves are functional (open/close), and grease and service valves as required to maintain functionality;
- chain and lock (or remove) valve handles;
- install bull plugs or blind flanges on all outlets except surface casing vents. Bull plugs and blind flanges must be equipped with plugged needle valves; and
- ensure that all wellheads are conspicuously marked or fenced such that they are visible in all seasons with well identification sign in plain view in accordance with *OGCR* section 8.192. In agricultural areas, farming operations must be restricted to safe distances from the wellhead.

The licensee must

- ensure that the wellhead is secured in accordance with *OGCR* section 8.193, and
- leave the surface casing vent open in accordance with *OGCR* sections 6.100(1), (2), and (3).

For sour wells, the wellhead must also meet the requirements of AER *Interim Directive 90-01* and Drilling and Completion Committee (DACC) *Industry Recommend Practice (IRP) Volume 2: Completing and Servicing Critical Sour Wells*.

It is recommended that a surface casing vent flow test be conducted in accordance with *Directive 020*. If there is no vent assembly as required under *OGCR* section 6.100, the licensee should refer to *Bulletin 2011-35: Surface Casing Vent Requirements for Wells*.

2.3.3 Associated Infrastructure

The licensee must leave all single well facility equipment associated with a suspended well in a secure state.

The licensee must discontinue or abandon pipelines associated with the suspended well in accordance with *Pipeline Rules*, part 10, section 82.

2.4 Repair Requirements

Wells that are suspended in accordance with this directive are not required to meet the annual isolation packer testing requirements of *Interim Directive (ID) 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirement; 3) Casing Failure Reporting and Repair Requirements*.

If a packer is used for the downhole suspension, the licensee must test the packer in accordance with the requirements of section 3. However, a failure in the packer must be reported and repaired in accordance with *ID 2003-01*.

Detection of a surface casing vent flow or gas migration must be reported, monitored, and repaired in accordance with *ID 2003-01*. The suspension report must also indicate the presence of the surface casing vent flow or gas migration.

Casing failures must be reported and repaired in accordance with *ID 2003-01*.

All other well integrity failures (example, leaking casing patch, remedial perforations, leaking plugs, etc.) must be reported through the designated information submission system and repaired within 90 days of failure detection.

All failures identified during ongoing inspections must be indicated in the inspection report as required. The noncompliant status will remain for the well until the deficiencies are repaired and the well inspection report is updated, respectively.

2.5 Reporting Requirements

The initial suspension and ongoing inspections for the inactive well must be reported to the AER via the designated information submission system in accordance with section 2.1. The reactivation of a well from suspension must be reported to the AER via the designated information submission system within 30 days after the well obtained an active status in accordance with section 4.

Licensees are responsible to ensure both the well status (Petrinex) and the Well Licence Status (AER designated information submission system) is updated and aligned with one another.

Note: Refer to *Directive 007: Volumetric and Infrastructure Requirements and Directive 059: Well Drilling and Completion Data Filing Requirements* for submitting amendments to the well status in Petrinex.

The following information must be reported to the AER:

Suspension date	Inhibitor program	Casing failure detected
Suspension class (risk)	Inspection date	Wellhead failure detected
Well operational type	Inspection reason	Inspection outcome
Downhole operation	Packer/plug failure detected	Remedial work completed
H_2S content (%)	Gas migration detected	
CO_2 content (%)	Vent flow detected	

3 Risk-Based Suspension Requirements

All inactive wells are divided into three categories based on the risk: low, medium, and high. Inactive wells must be classified and suspended as defined in this directive. Table 1 summarizes the suspension requirements for all inactive wells according to the risk level the well falls under.

3.1 Low-Risk Wells

Low-risk well is defined as one of the following:

Type 1. Cased-hole wells that are not critical sour and have no perforations (noncompleted)

Type 2. Gas wells less than 28 000 m^3/day that are low risk (see appendix 1)

Type 3. Water source wells

Type 4. Class 4 injectors (see *Directive 051,* section 2)

Type 5. Nonflowing[1] oil wells with an H_2S content less than or equal to 50 moles per kilomole (mol/kmol)

[1] Nonflowing refers to wells without sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid.

3.1.1 Initial Suspension Requirements

Initial Suspension

There are no downhole requirements for low-risk wells, as the wells do not pose a significant risk while suspended. The licensee must measure and record the shut-in tubing pressure (if tubing is present) and shut-in casing pressure.

Wellbore Fluid

Filling the wellbore with fluid is not required; however, if fluid *is* to be placed in the wellbore for suspension purposes, it must be nonsaline water or an inhibited (noncorrosive) fluid, and the top two metres of the wellbore must be filled with a nonfreezing fluid.

Wellhead

The licensee must ensure the following:

- Completed wells have a standard wellhead installed as outlined in *OGCR* sections 6.100(3), 6.130(1)(2), 7.050(3), and 7.060(8).
- Wells that have no perforations (noncompleted) have either a wellhead or a welded steel plate equipped with a test port on the production casing stub, or equivalent.

3.1.2 Ongoing Inspection Requirements

The wellhead must be maintained and tested in accordance with section 2.3.

For the low-risk well under type 1, type 2, type 3, and type 4, the licensee must measure and record the shut-in casing pressure and shut-in tubing pressure (if tubing is present) every five years.

For the low-risk wells under type 5, the licensee must measure and record the shut-in casing pressure and shut-in tubing pressure (if tubing is present) every year.

Licensees must notify the AER of all surface casing vent flows, gas migration, wellhead seal leaks, and casing failures and must address them as per the requirements in *ID 2003-01*.

3.2 Medium-Risk Wells

Medium-risk well is defined as one of the following:

Type 1. Gas wells that are medium risk (see the appendix 1)

Type 2. Nonflowing oil wells with an H_2S content more than 50 mol/kmol

Type 3. Flowing oil wells

Type 4. Class 2 & 3 injection, carbon dioxide (CO_2) injection/disposal wells (see *Directive 051*, section 2)

Type 5. Class 1B waste disposal wells (see *Directive 051*, section 2)

Type 6. Low-risk wells inactive for more than 10 years

All cavern wells. The licensee must submit a nonroutine application to WellOperations@aer.ca for the suspension of the well and the cavern.

3.2.1 Initial Suspension Requirements

Initial Suspension

It is recommended that licensees refer to *Directive 020* when determining the bridge plug type and setting depths. Not all suspension methods (for example, retrievable bridge plugs, packers with a tubing plug) are acceptable abandonment methods.

For medium-risk type 1, 2, 3, 4, and 5 wells, the licensee must do one of the following:

- Option 1 – set a packer and a tubing plug as close as possible to the packer setting element. The casing and tubing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.
- Option 2 – set a bridge plug above the uppermost completed interval. The casing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.

For medium-risk type 6 wells, the licensee must do one of the following:

- Option 1 – set a packer and a tubing plug as close as possible to the packer setting element. The casing and tubing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.
- Option 2 – set a bridge plug above the uppermost completed interval. The casing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.
- Option 3 – *If the licensee has an AER-approved closure plan*, measure and record the shut-in casing pressure and shut-in tubing pressure (if tubing is present).

Wellbore Fluid

For medium-risk type 1, 2, 3, 4, and 5 wells:

The licensee must fill the well with nonsaline water or an inhibited (noncorrosive) fluid. The top two metres must be filled with a nonfreezing fluid.

For medium-risk type 6 wells:

If the licensee has an AER-approved closure plan, filling the wellbore with fluid is not required; however, if fluid *is* to be placed in the wellbore for suspension purposes, it must be nonsaline water or an inhibited (noncorrosive) fluid, and the top two metres of the wellbore must be filled with a nonfreezing fluid.

Wellhead

- The licensee must ensure that a standard wellhead is installed as outlined in *OGCR* sections 6.100(3), 6.130(1)(2), 7.050(3), and 7.060(8).
- If the licensee has an AER-approved closure plan, they must ensure the medium-risk type 6 wells that were previously classified as low-risk type 1 have either a wellhead or a welded steel plate equipped with a test port on the production casing stub, or equivalent.

3.2.2 Ongoing Inspection Requirements

For medium-risk type 1, 2, 3, 4, 5 wells, the licensee must do either option 1 or option 2:

- Option 1 – The casing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes. And the tubing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes every three years.
- Option 2 – The casing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes every five years.

For medium-risk type 6 wells, the licensee must do either option 1, 2, or (if applicable) 3:

- Option 3 – *If the licensee has an AER-approved closure plan*, it must do all of the following:
  - Measure and record the shut-in casing pressure and shut-in tubing pressure (if tubing is present) every year. The AER must be notified if any pressure anomalies are noted during the annual testing.
  - Perform the wellhead inspection requirements in accordance with section 2.3 either
    - every year for wells previously classified as low-risk type 5 or
    - every five years for all other low-risk well types.

Licensees must notify the AER of all surface casing vent flows, gas migration, wellhead seal leaks, and casing failures and must address them as per the requirements in *ID 2003-01*.

3.3 High-Risk Wells

High-risk well is defined as one of the following:

Type 1. Critical sour wells, perforated or not.

Type 2. Acid gas wells.

Type 3. Class 1A waste disposal wells (see *Directive 051*, section 2).

3.3.1 Initial Suspension Requirements

Initial Suspension

For all high-risk wells, the licensee must complete the following:

- Option 1 – set a packer and a tubing plug as close as possible to the packer setting element. The casing and tubing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.
- Option 2 – set a permanent bridge plug above the uppermost completed interval and cap it with eight linear metres of cement. The casing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.

It is recommended that licensees refer to *Directive 020* when determining the setting depths and downhole plug type. Not all suspension methods (for example, packers with a tubing plug) are acceptable abandonment methods.

Wellbore Fluid

The licensee must fill the well with nonsaline water or an inhibited (noncorrosive) fluid. The top two metres must be filled with a nonfreezing fluid.

Wellhead

The licensee must ensure that a standard wellhead installed as outlined in *OGCR* sections 6.100(3), 6.130(1)(2), 7.050(3), and 7.060(8).

3.3.2 Ongoing Inspection Requirements

The wellhead must be maintained and tested in accordance with section 2.3.

For option 1, the licensee must complete the following every year:

- The casing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.
- The tubing must be pressure tested to a stabilized pressure of 7000 kPa for 10 minutes.

For option 2, the licensee must pressure test the casing to a stabilized pressure of 7000 kPa for 10 minutes every five years.

Table 1. Suspension requirements for all inactive wells

	Low-risk well	Medium-risk well	High-risk well
Well types	**Type 1**. Cased-hole wells that are not critical sour – no perforations. **Type 2**. Gas wells < 28 000 m^3/day[1] that are low risk (see the appendix). **Type 3**. Water source wells. **Type 4**. Class 4 injectors (see *Directive 051,*[2] section 2). **Type 5**. Nonflowing[3] oil wells with an H_2S content ≤ 50 moles per kilomole (mol/kmol).	**Type 1**. Gas wells that are medium risk (see the appendix) **Type 2**. Nonflowing[3] oil wells > 50 mol/kmol H_2S. **Type 3**. Flowing oil wells. **Type 4**. Class 2 & 3 injection, carbon dioxide (CO_2) injection/disposal wells (see *Directive 051*, section 2). **Type 5**. Class 1B waste disposal wells (see *Directive 051*, section 2) **Type 6**. Low-risk wells inactive longer than 10 years.	**Type 1**. Critical sour wells, perforated or not. **Type 2**. Acid gas wells. **Type 3**. Class 1A waste disposal wells (see *Directive 051*, section 2).
Downhole requirements	There are no downhole requirements.	**Option 1**. Packer and a tubing plug. **Option 2**. Bridge plug. **Option 3.** No downhole plug requirements (applicable only to type 6 wells; AER approval required).	**Option 1**. Packer and a tubing plug. **Option 2**. Permanent bridge plug capped with 8 linear metres of class "G" cement.
Initial suspension & Ongoing Inspection requirements	**Types 1, 2, 3, 4, 5**. Read and record shut-in tubing pressure and shut-in casing pressure.	**Option 1**. Pressure test casing and tubing to 7 MPa for 10 minutes. **Option 2**. Pressure test casing to 7 MPa for 10 minutes. **Option 3.** Read and record shut-in tubing pressure (if tubing is present) and shut-in casing pressure (applicable only to type 6 wells; AER approval required).	**Option 1**. Pressure test casing and tubing to 7 MPa for 10 minutes. **Option 2**. Pressure test casing to 7 MPa for 10 minutes.
Inspection frequency	**Types 1, 2, 3, 4** – 5 years. **Type 5** – 1 year.	**Option 1** – 3 years. **Option 2** – 5 years. **Option 3** – Read and record shut in tubing pressure (if tubing is present) and shut in casing pressure every year (applicable to only type 6 wells; AER approval required).	**Option 1** – 1 year. **Option 2** – 5 years.
Wellbore fluid	None	Wellbore fluid is to be nonsaline water or a noncorrosive (inhibited) fluid, with a nonfreezing fluid in the top 2 m. <u>For medium-risk type 6 wells that have AER approval to be suspended using option 3</u> Filling the wellbore with fluid is not required; however, if fluid *is* to be placed in the wellbore for suspension purposes, it must be nonsaline water or an inhibited (noncorrosive) fluid, and the top two metres (m) of the wellbore must be filled with a nonfreezing fluid.	
Wellheads	Unperforated (noncompleted) wells may use a welded steel plate atop the production casing stub. The plate must provide access to the wellbore for pressure measurement. Perforated wells are to have standard wellheads.	Standard wellheads as outlined in the *OGCR*, sections 6.100(3), 6.130(1)(2), 7.050(3), and 7.060(8). <u>For medium-risk type 6 wells that were previously low-risk type 1 and have AER approval to be suspended using option 3</u> Unperforated (noncompleted) wells may use a welded steel plate atop the production casing stub. The plate must provide access to the wellbore for pressure measurement.	
Reporting	**For initial suspension:** within 12 months from the "*Directive 013* Inactive Status Date" and after the completion of initial suspension. **For ongoing inspections:** by the end of the calendar year in which the inspection due date is calculated and after the completion of the inspection. For the reactivation: within 30 days after attaining active status.		
Wellhead maintenance	There shall be no wellhead leaks. Regular wellheads require servicing and pressure testing of sealing elements at time of suspension and at each subsequent inspection. All outlets except surface casing vents are to be bull plugged or blind flanged with needle valves. Valves must be functional (open/close). Grease and service as required to maintain functionality.		
Security	All wellheads are to be conspicuously marked or fenced such that they are visible in all seasons with well identification sign in plain view. In agricultural areas, farming operations must be restricted to safe distances from the wellhead. Pumpjacks must be left in a secure condition. Valve handles must be chained and locked, or as an alternative, valve handles may be removed.		
Surface casing vent flows	Systems must be open and comply with the OGCR, sections 6.100(1), (2), and (3). Vent flows, if detected, are to be handled as described in *ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements.*		

[1] This flow rate is the stabilized wellhead absolute open flow.

[2] *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements*.

[3] Nonflowing refers to wells without sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid.

4 Reactivating Suspended Wells

The licensee must complete all the following procedures (as applicable) for the reactivation of a suspended well.

All Wells

- Inspect, service, and pressure test the wellhead.
- Inspect and service control systems and lease facilities.
- Report reactivation of well on the designated information submission system within 30 days after it attained an active status and retain records.

Medium-Risk Type 1, 2, 3, 4, and 5 and High-Risk Wells

- Pressure test the casing to 7 MPa for 10 minutes. If this test fails, then the problem must be investigated and repaired.
- If tubing is present, pressure test the tubing to 7 MPa for 10 minutes. If this test fails, then the problem must be investigated and repaired.

Pressure test results are valid for 12 months. Pressure testing casing and tubing for the reactivation of a well is not required if the initial well suspension was completed less than 12 months before reactivation.

A well attains active status after it reports volumetric activity for at least one hour per month for three consecutive months. A well that cannot meet this requirement retains an inactive status.

Flaring or venting is not considered to be a volumetric activity.

5 Long-Term Suspension Requirements

All low-risk wells must meet suspension requirements for medium-risk wells after being inactive for 10 consecutive years after the first year of inactivity. The following examples demonstrate the timing of the long-term suspension requirements.

Example: A never-perforated low-risk well (type 1) that was drilled in August 2005.

On August 31, 2006, the well will become inactive and the licensee will have 12 months to suspend the well in accordance with the low-risk well requirements of this directive and report it to the AER on the designated information submission system. Thus, the compliance deadline date for the low-risk initial suspension is August 31, 2007.

On August 31, 2016, if the well is still inactive, the licensee will have 12 months to suspend this well in accordance with the medium-risk well requirements of this directive. This means all the required work must be completed and reported on the designated information submission system by August 31, 2017.

6 Audit and Enforcement Process

The initial compliance assessment is conducted by the AER and the results are compiled on the inactive well licence list available on the designated information submission system. "*Directive 013* Compliance Status" and "Noncompliance Details" provided in the inactive well licence list are automatically calculated based on the information reported on the designated information submission system under Well Licence Suspension Report and based on historical volumetric activity reported on Petrinex.

The licensee is expected to submit true and accurate information in reports submitted through the designated information submission system. It is also expected that the licensee has read and understood all *Directive 013* requirements. Failure to submit true and accurate information or to comply with *Directive 013* requirements may result in subsequent enforcement by the AER.

The licensee must keep all documentation related to suspension operations (field reports, test results, suspension details, inspection records, pictures, etc.) for suspended wells until the well abandonment is completed in accordance with *Directive 020*.

The AER will conduct audits or field inspections, or both, to verify the licensee's compliance with *Directive 013*. Upon written notification that the well has been selected for audit, the licensee must submit the required information within 20 calendar days.

Information on compliance and enforcement can be found on the AER website. Under the AER's compliance assurance program, self-disclosures or extensions pertaining to *Directive 013* requirements will not be accepted.

Appendix 1 Classifying Suspended Gas Wells

In order to classify the risk of gas wells containing H_2S for well suspension purposes, an equation determining distances to predicted concentrations is used.

The following equation for low H_2S release rates ($0.01\ m^3/s < Q$ [flow rate] $< 0.3\ m^3/s$ of H_2S) gives the distance to in kilometres (km) to an ambient concentration of 100 parts per million (ppm):

$$\text{Distance to 100 ppm} = 2.0\ (Q)^{0.58}$$

A similar equation to the above with a slightly different constant (1.9145) and exponent (0.5765) can be derived assuming an exposure to 100 ppm of H_2S from a ground-based release with no plume rise and with a wind speed of 2 m/s using the U.S. Environmental Protection Agency rural plume dispersion parameters (one hour average) for very stable F-class (from the Pasquill-Gifford stability classification) stability conditions. These are typically considered to be the worst-case dispersion conditions.

The equation can be modified to predict the distance for other values of H_2S. If the occupational exposure limit of 10 ppm for an eight-hour working day is applied to the same averaging time, the equation becomes:

$$\text{Distance to } 10\text{ ppm} = 2.0 \cdot \left(\frac{100}{10}\right)^{0.58} \cdot (Q)^{0.58} = 7.6 \cdot (Q)^{0.58}$$

Figure 1 shows acceptable combinations of total flow rate and H_2S concentration for a release to disperse to 10 ppm at the 50 m lease edge. For example, a well with a 28 000 m^3/day (~1 million standard cubic feet of gas per day) potential (stabilized wellhead absolute open flow [AOF]) release rate containing 533 ppm H_2S will result in an H_2S concentration of 10 ppm at 50 m from the wellhead, the edge of a typical lease.

The AER defines a low-risk well as a combination of flow rate and H_2S concentration, with a maximum flow rate less than 28 000 m^3/day (stabilized wellhead AOF). The 28 000 m^3/day is considered to be surface killable derived from fluid momentum theory. Medium-risk wells have combinations of flow rate and H_2S concentrations above and to the right of the vertical line.

If from a given AOF and H_2S content, the conditions for the well fall below the line into the low-risk zone, the well will be considered to be low risk. If the well falls above this line, it will be considered medium risk, unless the well is considered critical sour.

To determine whether a gas well falls into the low-risk category, use the following equation, which is derived from the above-mentioned conditions:

$$\frac{15\ 000}{H_2S\,(\text{ppm})} = \text{Allowable flow rate}\left(10^3\,\text{m}^3\!/\text{day}\right)$$

The maximum flow rate for any concentration of H_2S remains at 28 000 m^3/day (stabilized wellhead AOF).

The following examples demonstrate how to calculate an allowable flow rate for a given H_2S concentration. This result is then used to classify the wells as low or medium risk.

Example 1: A gas well has a flow rate of 26 000 m^3/day (stabilized wellhead AOF) at 352 ppm H_2S.

The allowable flow rate at that concentration is

$$\text{Allowable flow rate} = \frac{15\ 000}{352\ \text{ppm}} = 42.614\ 10^3\ \text{m}^3/\text{day} = 42\ 614\ \text{m}^3/\text{day}$$

The actual flow rate of 26 000 m^3/day is less than the allowable flow rate of 42 614 m^3/day, making this well low risk.

Example 2: A gas well has a flow rate of 5230 m^3/day (stabilized wellhead AOF) at 4000 ppm H_2S.

The allowable flow rate at that concentration is

$$\text{Allowable flow rate} = \frac{15\ 000}{4000\ \text{ppm}} = 3.750\ 10^3\ \text{m}^3/\text{day} = 3750\ \text{m}^3/\text{day}$$

The actual flow rate of 5230 m^3/day is greater than the allowable flow rate of 3750 m^3/day, making this well medium risk.

Example 3: A gas well has a flow rate of 32 000 m^3/day (stabilized wellhead AOF) at 0 ppm H_2S.

The allowable flow rate at that concentration is irrelevant; the actual flow is greater than 28 000 m^3/day, making this well medium risk.

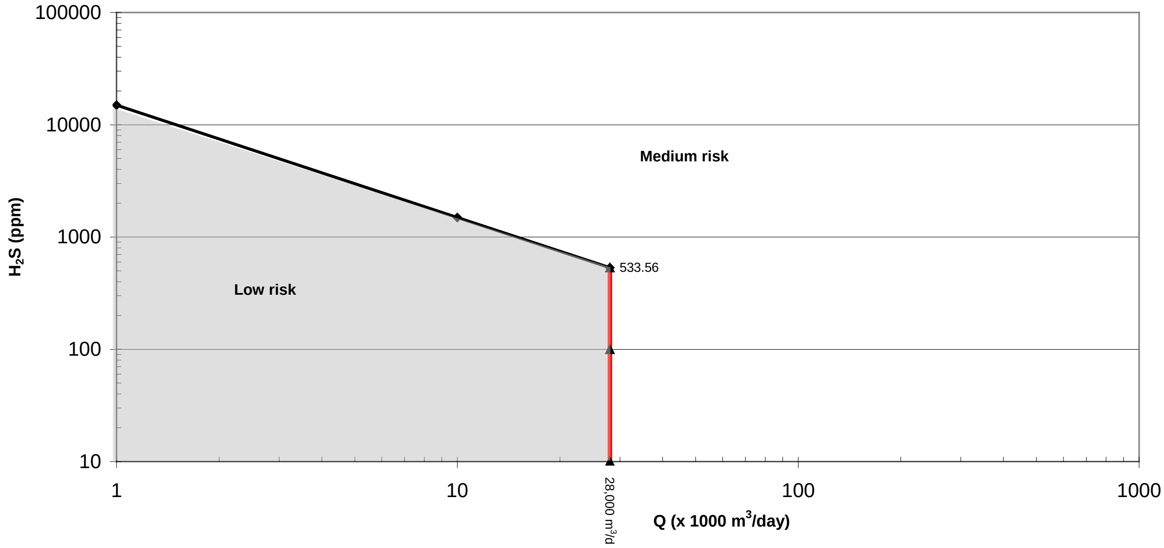

Figure 1. Source flow rate and H_2S for 50 m distance to 10 ppm H_2S

Appendix 2 Definitions

abandoned well	A well that has been downhole abandoned, surface abandoned and the well licence status is "abandoned."
absolute open flow	The stabilized wellhead absolute open-flow rate.
cased-hole well	A well that has production casing or any combination of surface casing, intermediate casing, production casing, and/or liner.
compliance	An inactive well is considered to be compliant with *Directive 013* if it meets the following requirements: • downhole (if applicable) • surface • ongoing inspections • reporting on the designated information submission system
completed well	A well that has been perforated, has a liner installed with openings for production or injection, or has an open-hole section.
critical sour well	A well licensed as a critical well under *Directive 056: Energy Development Applications and Schedules*.
inactive well	An inactive well is defined as follows: • Critical sour wells (perforated or not) that have not reported any type of volumetric activity (production, injection, or disposal) for six consecutive months. • All other wells that have not reported any type of volumetric activity (production, injection, or disposal) for 12 consecutive months.
licensee	The holder of a facility, pipeline, or well licence according to the records of the AER; includes the trustee or receiver-manager of a licensee's property.
noncompleted well	A well that has not been perforated, has no liner installed with openings for production or injection, or has no open-hole section.
nonflowing oil well	A well without sufficient reservoir pressure to sustain flow against atmospheric pressure without artificial lift. The flowing product is a fluid.
nonsaline water	Water that has total dissolved solids less than or equal to 4000 milligrams per litre.

open-hole well	A well that has an open-hole interval and is required to be downhole abandoned before the drilling rig is released.
suspended well	A well whose initial suspension has been completed and reported as per *Directive 013* requirements.
zonal abandonment	The abandonment of a completed or open-hole interval in a cased well in accordance with *Directive 020*.