Suspension Requirements for Wells

July 24, 2007

Effective January 1, 2008, the Alberta Energy and Utilities Board (EUB) has been realigned into two separate regulatory bodies, the Energy Resources Conservation Board (ERCB), which regulates the energy industry, and the Alberta Utilities Commission (AUC), which regulates the utilities industry.

As part of this realignment, the title pages of all existing EUB directives now carry the new ERCB logo. However, no other changes have been made to the directives, and they continue to have references to “EUB.” As new editions of the directives are issued, these references will be changed.

ENERGY RESOURCES CONSERVATION BOARD
Directive 013: Suspension Requirements for Wells

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Directive 013

Revised edition July 24, 2007

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The Alberta Energy and Utilities Board (EUB/Board) has approved this directive on July 24, 2007.

[Original signed by]

B. T. McManus, Q.C.
Acting Chairman

Contents

1 Suspension Requirements for Wells

This Alberta Energy and Utilities Board (EUB) directive sets out the requirements for the suspension of inactive wells.

1.1 What's New in This Edition

Updates in this edition of the directive cite compliance information in *Directive 019: EUB Compliance Assurance—Enforcement*, with references to the matrix of risk items on the EUB Web site where applicable. References to other EUB published documents have also been updated as required.

This directive replaces the following documents, which are rescinded:

- *Interim Directive (ID) 90-4: Suspension Guidelines for Inactive Wells*, and
- *Interim Directive (ID) 91-5: Suspension Guidelines Compliance Schedule and Application Requirements for Inactive Wells.*

2 Definitions

For the purpose of this directive and the associated required practices, inactive wells are defined as follows:

- inactive critical sour and inactive acid gas wells—wells that have not reported any type of volumetric activity (production, injection, or disposal) for 6 consecutive months; and
- all other inactive wells—wells that have not reported any type of volumetric activity (production, injection, or disposal) for 12 consecutive months.

For the purpose of this directive, critical sour wells have been divided into four categories, based on hydrogen sulphide (H_2S) release rates in proximity to urban centres, and are defined as follows:

1) H_2S release rate of 0.01 cubic metres per second (m^3/s) or greater and less than 0.1 m^3/s and located within 500 m of the corporate boundaries of an urban centre, or

2) H_2S release rate of 0.1 m^3/s or greater and less than 0.3 m^3/s and located within 1.5 kilometres (km) of the corporate boundaries of an urban centre, or

3) H_2S release rate of 0.3 m^3/s or greater and less than 2.0 m^3/s and located within 5 km of the corporate boundaries of an urban centre, or

4) H_2S release rate of 2.0 m^3/s or greater.

3 Well Categories and Requirements

Table 1 describes the suspension requirements for all inactive wells according to which of three risk levels the well falls into.

Wells in a particular risk category may also be suspended in accordance with the requirements of any higher risk category.

For wells with multiple zones:

- the well must be classified as per the highest risk zone in the wellbore that has not been completely and properly abandoned, in accordance with *Directive 020: Well Abandonment Guide* (i.e., a bridge plug capped with 8 m of cement);
- if all zones are abandoned (the well has not yet been surface abandoned), the shallowest completion shall be used to classify the risk category for the well.

A licensee may request an extension of a deadline or a variance from technical requirements set out in this directive by submitting an application to the EUB Well Operations Section for review and disposition. Licensees requiring assistance regarding these requirements should contact EUB Well Operations at (403) 297-5290.

Table 1. Suspension requirements for all inactive wells

	Low-risk well	Medium-risk well	High-risk well
Well types	**Type 1.** Noncritical sour cased wells - 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[2] 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), and cavern service wells. **Type 6.** Completed low-risk wells suspended 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, as these wells do not pose a significant risk while suspended.	**Option 1.** Packer and a tubing plug. **Option 2.** Bridge plug. **Option 3.** Type 5 cavern service wells only. All product to be evacuated from the cavern and replaced with saturated brine. All hanging tubing/casing strings to be removed and a bridge plug set.	**Option 1.** Packer and a tubing plug. **Option 2**. Bridge plug capped with 8 m lineal cement.
Inspection/ monitoring/ pressure testing requirements	**Type 1.** Pressure test casing to 7 megapascals (MPa) for 10 minutes. **Type 2, 3, 4, 5.** Read and record shut-in tubing pressure (SITP) and shut-in casing pressure (SICP).	**Option 1.** Pressure test annulus and tubing to 7 MPa for 10 minutes. **Option 2, 3.** Pressure test casing to 7 MPa for 10 minutes.	**Option 1.** Pressure test annulus 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 2,3** – 5 years.	**Option 1** – 1 year. **Option 2** – 5 years.
Reporting	Within 30 days after completion of inspection or suspension operations. Within 30 days after resumption of production/injection.		
Wellbore fluid	None	Wellbore fluid is to be inhibited with a nonfreezing fluid in the top 2 m.	
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. Perforated wells are to have standard wellheads.	Standard wellheads as outlined in *Oil and Gas Conservation Regulations*. 6.100(3), 6.130(1)(2), 7.050(3), 7.060(8), *ID 98-02*, *ID 97-6*, *IRP (ARP) 2*, *IRP 5* and *API - 6A*. *CSA Z341* (Caverns)	
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 *Oil and Gas Regulations* 6.100 (1) (2) (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 (AOF).
[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 following are the required procedures 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 Digital Data Submission (DDS) system and retain records.

Medium 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.

A well attains active status after it has operated for a minimum of 360 hours (15 days) per month for 3 consecutive months.

5 Long-Term Suspension Requirements

All completed low-risk wells must meet suspension requirements for medium-risk wells after being suspended for 10 consecutive **years after the first year of inactivity** commencing December 31, 2007. The following examples demonstrate the timing of the long-term suspension requirements.

Example 1: A low-risk oil well that last reports production in December 2005

- On *December 31, 2006*, the licensee will have 60 days to suspend the well in accordance with the low-risk well requirements of this directive.
- The suspension operations must be reported within 30 days following the suspension operations.
- On *December 31, 2016*, if the well is still suspended, the licensee will have 60 days to suspend this well in accordance with the **medium**-risk well requirements of this directive.

Example 2: A low-risk oil well that last reports production in December 1994

- As of December 31, 2007, if the well is still suspended, the well must be suspended in accordance with the **medium**-risk well requirements of this directive.

All low-risk wells whose 10-year anniversary of inactivity occurs after December 31, 2007, must be suspended in accordance with the **medium**-risk well requirements no later than 60 days after the anniversary date.

All low-risk wells whose 10-year anniversary of inactivity occurs before December 31, 2007, must be suspended in accordance with the **medium**-risk well requirements by December 31, 2007.

6 Suspended Wells Relating to Isolation Packer Testing and Surface Casing Vent Flows

Packer Testing

- Wells that are suspended are to be removed from the packer testing system and the requirements of this directive must be met.

Surface Casing Vent Flow/Gas Migration

- The suspension of a well does not change any of the requirements of *ID 2003-01*.

7 Audit and Enforcement Process

The licensee must keep all test results and suspension details for suspended wells until well abandonment. The EUB will use an audit system to confirm the licensee's compliance and to help measure the effectiveness of the suspension process. Upon written notification that the well has been selected for audit, the licensee must submit the required information within 20 days.

The EUB's enforcement process is specified in *Directive 019: EUB Compliance Assurance-Enforcement*. A list of risk-assessed noncompliances is available on the Web at EUB Home : Industry Zone : Compliance and Enforcement : Risk Assessed Noncompliance.

8 Reporting and Repair Requirements

Inactive wells must be suspended according to the requirements of this directive within 60 days after the one-year anniversary of no production or injection. The suspension must be reported to the EUB via DDS within 30 days of the suspension operations or inspection. The reactivation of a well from suspension must be reported to the EUB via DDS within 30 days following the resumption of production or injection of the well.

For example, if a gas well's last production occurs April 29, 2003, the well must be suspended in compliance with requirements by June 28, 2004. The suspension must then be reported to the EUB DDS system within 30 days following completion of suspension operations.

Critical sour wells must be properly suspended within 6 months, as set out in *ID 90-1: Completion and Servicing of Sour Gas Wells* and reported within 30 days from the last day of suspension operations being completed.

The data elements required to be submitted include the following:

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	

9 Procedure and Schedule to Bring Wells into Compliance

Wells that are in the inventory of inactive wells at the time of issuance of this directive must be brought into compliance and reported according to the following schedule:

- All high-risk wells are to be in compliance with the requirements of this directive by December 31, 2005.
- All medium- and low-risk wells are to be in compliance with the requirements of this directive by December 31, 2006.

The reporting of these wells (both initially and following inspections) may be done by a batch upload available on the EUB Web site at https://www3.eub.gov.ab.ca/eub/dds.

Licensees having difficulty meeting the above schedule should contact EUB Well Operations at (403) 297-5290 prior to the deadline to discuss options available to meet the compliance expectations.

Critical sour wells must be properly suspended within 6 months, as set out in *ID 90-1*.

Appendix Classifying Suspended Gas Wells

In order to classify the risk of gas wells containing H_2S, the EUB equation for the emergency planning zone (EPZ) 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 the EPZ in kilometres (km) an ambient concentration of 100 parts per million (ppm):

$$\mathrm{EPZ} = 2.0\ (Q)^{0.58}$$

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 EUB EPZ equation can be modified to predict the distance for other values of H_2S. If the occupational exposure limit of 10 ppm for an 8-hour working day is applied to the same averaging time used for the EUB EPZ, 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 [MMSCFD]) potential (stabilized wellhead 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 EUB 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 if a gas well falls into the low-risk category, use the following equation, which is derived from the above-mentioned conditions:

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

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**.

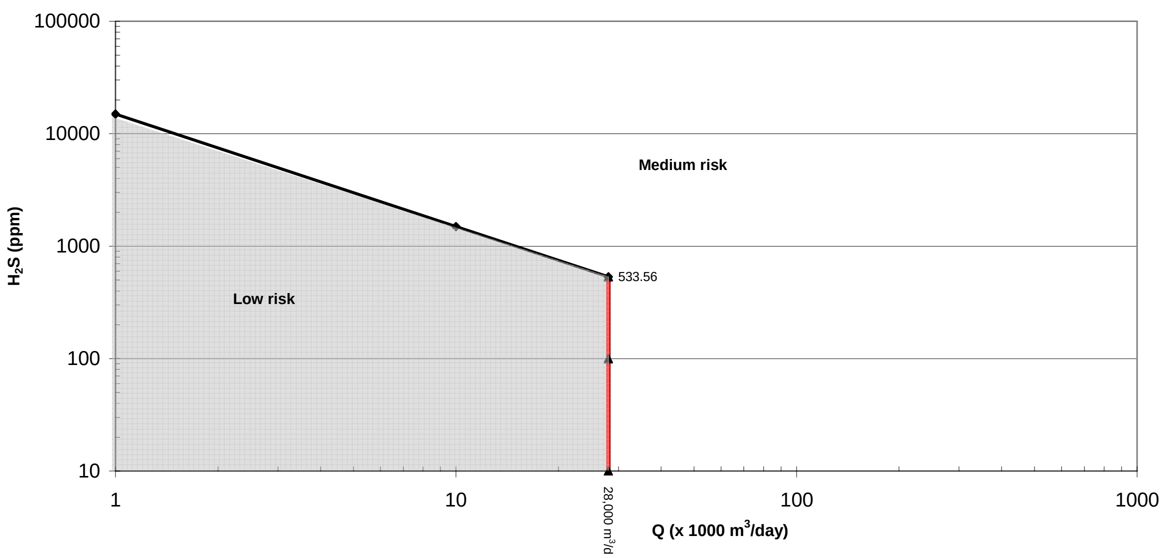

Figure 1. Source flow rate and H_2S For 50 m distance to 10 ppm H_2S