Directive 036 – Addendum 2015-05-19

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Replaces addendum issued December 9, 2013

Drilling Blowout Prevention Requirements and Procedures

The Alberta Energy Regulator has approved this addendum to *Directive 036* on May 19, 2015.

<*original signed by*>

Jim Ellis
President and CEO

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1 Introduction

1.1 Purpose of this Addendum

This addendum modifies requirements in *Directive 036* and will be incorporated into *Directive 036* in due course. This incorporates and replaces the previous addendum, issued December 9, 2013.

This addendum consists of two main parts:

- the first part incorporates the definitions and requirements around underbalanced drilling that are in the 2013 addendum.
- the second part entirely replaces section 7, "Pressure Testing," of *Directive 036*, and provides an alternative pressure testing method.

1.2 ~~Compliance Assurance~~

~~AER requirements are rules that a licensee is required to follow. The term "must" indicates a requirement, while terms such as "recommends" and "expects" indicate recommended practices. Each AER requirement is numbered and has been risk assessed. Noncompliance with a requirement will result in a licensee receiving a response in accordance with the latest edition of *Directive 019*.~~

~~*Compliance Assurance*. A list of noncompliant events is available from the AER website, www.aer.ca.~~

~~The AER encourages each licensee to be proactive by monitoring its compliance with AER requirements. If a licensee identifies a noncompliance, it should inform the AER of the noncompliance under the AER Voluntary Self-Disclosure Policy set out in *Directive 019*. For further details on compliance assurance, including *Directive 019*, see the AER website, www.aer.ca~~.

2 Underbalanced Drilling Requirements

This part incorporates provisions of the 2013 addendum. The AER defines underbalanced drilling as follows:

> When the hydrostatic head of a drilling fluid is intentionally designed to be lower than the pressure of the formation being drilled, the operation will be considered underbalanced drilling. The hydrostatic head of the drilling fluid may be naturally less than the formation pressure or it can be induced. The induced state may be created by adding natural gas, nitrogen, or air to the liquid phase of the drilling fluid. Whether induced or natural, this may result in an influx of formation fluids which must be circulated from the well and controlled at surface.

For all underbalanced drilling operations, a licensee must

1) ensure that the blowout prevention system complies with *IRP 22: Underbalanced and Managed Pressure Drilling Operations Using Jointed Pipe* (appendices A to D) or *IRP 15: Snubbing Operations*;
2) have adequate snubbing, tripping, and stripping procedures in accordance with IRPs 15 and 22 and *Directive 036: Drilling Blowout Prevention Requirements and Procedures*; and
3) ensure that well site personnel are
    a) supervised and certified in accordance with AER *Directive 036*, and
    b) are trained and certified in accordance with *IRP 21: Coiled Tubing Operations* if conducting a coiled tubing operation.

Licensees are reminded of the requirement to disclose underbalanced drilling operations to the AER in accordance with *Directive 056*: *Energy Development Applications and Schedules* and are further reminded to refer to *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.

The AER strongly encourages licensees to follow the Drilling and Completions Committee's *Industry Recommended Practice (IRP) 22* and other appropriate industry recommended practices when conducting underbalanced drilling operations.

3 Alternative Pressure Testing Methods for Blowout Prevention Equipment

This part replaces the text in section 7, “Pressure Testing,” of *Directive 036* in its entirety.

7 Pressure Testing

Before drilling out the surface, intermediate, and production casing, the licensee must ensure that the following components (when required or in use) are pressure tested: each blowout preventer (BOP), casing string, stabbing valve, inside BOP, lower kelly cock, choke manifold, bleed-off and kill lines, and all associated valves.

7.1 Class I Wells

Class I wells do not require BOP pressure testing. However, a leak test of a minimal pressure is recommended.

7.2 Well Classes II to VI

For well classes II to VI, pressure testing must be conducted as follows:

- The pressure test must be conducted using a low-viscosity fluid.
- The low-pressure test must be conducted before the high-pressure test.
- All valves in the choke manifold and bleed-off and kill systems must be individually pressure tested to confirm their isolation.

  Adjustable chokes do not require pressure testing. It is recommended that the adjustable chokes be confirmed as functional by pumping fluid through the chokes and noting restriction ability.
- The stabbing valve, inside BOP, and lower kelly cock (when required or in use) must be pressure tested from the bottom.

  An inside BOP consisting of pump-down check valve and a landing sub that is an integral part of the drill string must also be pressure tested.
- A casing hanger plug must be run to isolate the surface/intermediate/production casing from the BOPs if the required test pressure will exceed 67 per cent of the bottomhole pressure (BHP) at the casing setting depth.
- Variable bore rams must be pressure tested on the largest and smallest drill pipe sizes that will be used in the drill string.
- For a satisfactory pressure test, all components must maintain a stabilized pressure of at least 90 per cent of the required test pressure over a minimum 10-minute interval.
- All pressure test details (i.e., individual BOP components tested, test duration, low- and high-pressure test details) must be recorded in the drilling logbook.

Third-party pressure test documentation is an acceptable substitute for detailed pressure test data entry in the drilling logbook. This documentation must be available at the rig and referenced in the drilling logbook.

Tables 4, 5, and 6 summarize the pressure testing requirements.

Alternatively, tables 7, 8, and 9 summarize the requirements for the alternative pressure testing method for class II, III, and IV wells when an intermediate casing string will be set in the well.

Note: This alternative pressure testing method excludes class V and VI wells, critical sour wells, and sour wells that require an AER-approved site-specific emergency response plan.

Table 4. Low-pressure testing requirements before drilling out the surface, intermediate, or production casing.

BOP equipment	Test pressure (kPa)	Test duration (minutes)
Annular	1400	10
Rams		
Bleed-off line and valves Manifold valves		
Kill line and valves		
Stabbing valve		
Inside BOP		
Lower kelly cock		

Table 5. High-pressure testing requirements before drilling out the surface casing.

BOP equipment	Test pressure (kPa)	Test duration (minutes)
Annular	The lesser of 7000 kPa or 50 times the setting depth (in metres) of the surface casing	10
Rams		
Bleed-off line and valves		
Manifold valves		
Kill line and valves		
Stabbing valve		
Inside BOP		
Lower kelly cock		
Surface casing		

Table 6. High-pressure testing requirements before drilling out the intermediate or production casing.

BOP equipment	Test pressure (kPa)	Test duration (minutes)
Annular	50 per cent of the working pressure of the required BOP system for the well class (see appendix 3)	10
Rams Bleed-off line and valves Manifold valves Kill line and valves Stabbing valve Inside BOP Lower kelly cock	To a minimum pressure of the required BOP system, based on the well class (see appendix 3; e.g., class III well: a minimum 14 000 kPa pressure test required)	10
Intermediate or production casing	A pressure equal to 67 per cent of the BHP at the casing setting depth after bumping the plug; if the actual BHP is unknown, a gradient of 11 kPa/m may be used to calculate a theoretical BHP (e.g., BHP = 11 kPa/m × casing setting depth in metres)	10

7.3 Alternative Method

For well classes II, III, and IV (excluding class V and class VI wells, critical sour wells, and sour wells that require an AER-approved site-specific emergency response plan), the following method may be used when an intermediate casing string will be set in the well.

Table 7. Low-pressure testing requirements prior to drilling out the surface casing (intermediate casing will be set in the well).

BOP equipment	Test pressure (kPa)	Test duration (minutes)
Annular Rams Bleed-off line and valves Manifold valves Kill line and valves Stabbing valve Inside BOP Lower kelly cock	1400	10

Table 8. High-pressure testing requirements prior to drilling out the surface casing (intermediate casing will be set in the well).

BOP equipment	Test pressure (kPa)	Test duration (minutes)
Surface casing	The lesser of 7000 kPa or 50 times the setting depth (in metres) of the surface casing	10
Annular	50 per cent of the working pressure of the required BOP system for the well class (see appendix 3)	10
Rams Bleed-off line and valves Manifold valves Kill line and valves Stabbing valve Inside BOP Lower kelly cock	To a minimum pressure of the required BOP system, based on the well class (see appendix 3; e.g., class III well: a minimum 14 000 kPa pressure test required)	10

Table 9. High-pressure testing requirements after intermediate casing is set.

BOP equipment	Test pressure (kPa)	Test duration (minutes)
Intermediate casing	A pressure equal to 67 per cent of the BHP at the casing setting depth after bumping the plug; if the actual BHP is unknown, a gradient of 11 kPa/m may be used to calculate a theoretical BHP (e.g., BHP = 11 kPa/m × casing setting depth)	10
Slip-Type Wellhead (Breaks to the BOP System)	To a minimum pressure of the required BOP system, based on the well class (see appendix 3; e.g., class III well: a minimum 14 000 kPa pressure test required)	10
Mandrel-Type Wellhead (Mandrel seals)	To a minimum pressure of the required BOP system, based on the well class (see appendix 3; e.g., class III well: a minimum 14 000 kPa pressure test required)	10