FAQs about *Directive 017*

General

What measurement points are covered in this directive?
The requirements in this directive cover all measurement points required by the *Oil and Gas Conservation Regulations* (*OGCR*) and other existing regulations for upstream petroleum facilities and some downstream pipeline operations, as well as those used for ERCB accounting and reporting purposes.

Does the ERCB test, approve, or endorse measurement devices?
No, the ERCB does not test, approve, or endorse any measurement devices. However, performance requirement standards for specific measurement points are set for industry to follow.

Are we allowed to exceed any requirements listed in this directive?
Directive 017 sets the minimum requirements for the oil and gas industry and any operator exceeding these requirements is considered to have met them.

Where do I have to install delivery point measurement?
Delivery point measurement is required at royalty trigger points within the upstream oil and gas systems and at cross-border facilities. See Sections 1.7.1 and 1.7.2 for oil and gas delivery points.

Does a straddle plant have to meet the requirements in this directive?
No, straddle plants are considered downstream facilities. As such, all gas from a straddle plant is royalty paid and not subject to *Directive 017* requirements.

Does a gas storage facility have to meet the requirements in this directive?
Yes, if the reservoir used for storage is not totally depleted and may still have some producible products. An exception is a salt cavern storage facility with only royalty-paid gas injection and withdrawal; it is considered a downstream facility.

Are there different types of well testing and reporting requirements?
Yes, there are two different types—pre-production testing under *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* to gather any well or reservoir information and production reporting testing under *Directive 017*. An operator must distinguish clearly between these two types of tests and know the reporting requirements for each type.

Is it a requirement to have an injection wellhead measurement for any injected fluid?
Yes. The requirement is for separate measurements of all fluid types at each wellhead before injection. See *OGCR*, Section 14.200, and *Directive 017,* Sections 1.7.3, 11.4.4.3, 12.4, and 15.2.4.

Section 1: Standards of Accuracy

What are the standards of accuracy?
They are the performance requirements for various measurement points. The standards include the uncertainty of all factors affecting the measurement accuracy at a single measurement point, such as the primary measurement element, calibration, proving, sampling and analysis, and water cut (see Section 1 for details). By setting performance requirements, the ERCB encourages industry to be innovative and try new measurement techniques or methodologies.

Do I have to prove to the ERCB that I have met the standards of accuracy for every measurement point?
No, if you follow the requirements, procedures, and industry standards stated in this directive, then you are considered to have met the standards of accuracy.

Section 2: Calibration and Proving

Does the frequency defined in Section 2.3 apply to the entire directive?
Yes, it does. However, the sampling and analysis requirements in Section 8.4 are more specific. There are no differences between the sampling frequency definitions in Section 2.3 and those in Section 8.4; the latter, however, provides a definition for "initial."

What steps are required to calibrate a differential-type meter, such as an orifice meter?
Section 2.5.3 of this directive sets out the requirements for calibrating an orifice meter, which can be used for any differential-type meters.

Is providing a concise statement (e.g., "left as found"), rather than filling in all the spaces on a calibration report, sufficient?
Yes, it is sufficient as long as the meaning is clear. Using an abbreviation, such as "LAF," <u>would not</u> be considered clear.

What is the calibration frequency for a gas rotary or turbine meter and the related instrumentation?
Annually for a pressure and/or temperature transducer. Though if it is at a delivery point or in a gas plant, then it is semi-annually. The rotary or turbine meter itself must be calibrated once every seven years. (See Section 2.5.2.1)

Is it permissible to use the internal diagnostics of a meter to check if the primary measurement element is functioning within acceptable operating parameters instead of performing an internal inspection?
Only if the meter has no internal moving parts, there are sufficient internal diagnostics built into the meter, and the appropriate software and hardware are used. (See Sections 2.5.2.1, items 9 and 2.6)

Section 3: Proration Factors, Allocation Factors, and Metering Differences

Are the proration factors enforceable?
No, these are non-enforceable targets set for the operator to achieve. However, inability to achieve these targets may signify an issue within the facility, which the ERCB may ask the operator to resolve.

Are metering differences enforceable?
Yes, for certain types of facilities and fluids (e.g., metering difference over 20% in a gas gathering system).

Section 4: Gas Measurement

What is mixed measurement?
Mixed measurement occurs when more than one type of measurement system is used at the various wells within a battery. For example, within a gas proration battery,

- there may be two- or three-phase separated and measured wells present together with proration tested wells, or
- some wells may have effluent (wet gas) measurement, while others do not.

Is it permissible to count the non-flowing hours as producing hours for a gas well using an on/off type operating system, such as a plunger lift?
Yes you may, provided that the well is operated on a cyclical on/off basis. For reporting, however, the Petroleum Registry of Alberta (PRA) limits the on/off cycle to less than a month, because you cannot report production hours without production volumes in most cases except in crude bitumen single-well batteries. The well(s) involved must have a PRA "GAS PUMP" well status. (See Sections 4.2. and 4.3.3.1)

What facilities require FUEL measurement?
Any oil and gas facility, such as a well site, gas plant, battery, or individual compressor site, that consumes fuel gas exceeding 0.5 10^3 m^3/d (annual average) on a per lease site basis must have fuel gas measurement. (See Sections 1.7.2(v) and 4.2.2)

What facilities require FLARE or VENT gas measurement?
Any oil and gas facility, such as a well site, gas plant, battery, or individual compressor site that flares gas in excess of 0.5 10^3 m^3/d (annual average) on a per site basis must have flare gas or vent gas metering. (See Section 1.7.2(vi))

Is it mandatory to have an inlet separator and separated measurement at a gas plant?
Yes, an inlet separator and separated measurement are required for each product stream entering a gas plant. (See Section 4.2.2.6 for exceptions)

Is gas measurement required at a gas plant outlet?
Yes, if it is for disposition or royalty determination purposes. For the stream that is measured by the gas receiver's measurement point, the plant outlet meter is for checking or reference

only and is not a requirement unless there are other gas streams tied in between the plant and the gas receiver's measurement point; then it is a requirement. (See Section 4.3.1)

Do I have to measure the dilution gas used when flaring acid gas?
Yes, it is a requirement regardless of the volume. (See *Directive 60*, Section 10.1)

Does the static pressure tap for orifice measurement have to be tied to one of the differential taps?
Yes, it must be from either the upstream or downstream tap in accordance with American Gas Association Report #3.

Do I have to use EFM for any kind of an on/off flow production, such as a plunger lift system?
No, unless you are implementing the exception in Section 5.3 for extended chart cycle or are ordered to do so by the ERCB, but it is recommended for better accuracy.

How do I report dilution, purge, or fuel gas added to a flare system?
Any fuel, purge, or dilution gas added to the flare must be reported as part of the total facility fuel usage, but must **not** be reported as part of the flared volumes. If there is a total flare gas meter, then the added fuel volume must be netted off the total measured volume before reporting the total FLARE volume. (See Sections 1.7.2(vi) and 4.3.3.1)

Do I have to report gas well pre-production testing volumes to the PRA?
Yes, volumetric reporting must be done under a gas test battery if flared or under a gas battery if tested in line.

Is there a maximum sensing line length requirement?
No. However, the operator should keep the sensing line length as short as possible to avoid the probability of increasing the measurement uncertainty, especially under pulsation conditions.

May I install needle valves at differential pressure sensing line taps?
Not any more; from February 2, 2009, onwards, there are to be full port valves installed at all measurement points so that there is no restriction of the sensing line diameter at delivery, group, or sales (royalty trigger) measurement points. However, needle valves installed before February 2, 2009, are grandfathered unless they are located at the latter measurement points. Operators had until February 1, 2010, to replace these valves with full port valves. (See Section 4.3.4.1)

Do I have to install self-draining differential pressure sensing lines?
Yes, from February 2, 2009, onwards, there must not be any non-self-draining differential sensing lines installed at any measurement point. However, non-self-draining differential sensing lines installed before February 2, 2009, are grandfathered unless they were installed at delivery, group, or sales (royalty trigger) measurement points; in which case, the operator had until February 1, 2010, to reconfigure the tubing to self-drain towards the sensing line tap valve. (See Section 4.3.4.1)

Is it permissible to install drip pots at wellheads or at other metering points where there are potential liquids in the differential sensing line?
No, from February 1, 2010, onwards, there must not be any drip pots installed at delivery, group, or sales (royalty trigger) measurement points. Any pre-existing drip pots at these measurement points must be removed and the sensing reconfigured to self drain towards the sensing line tap valve. The operator may install drip pots at other measurement points.

Do I have to apply to use a GOR for gas production determination at an oil well?
No, not if you meet the requirements in Section 4.3.5 for conventional oil or Section 12.3.2 for heavy oil/crude bitumen.

Section 5: Site-specific Deviation from Base Requirements

Do I have to apply for all measurement exemptions or deviations from a requirement?
No, not if the initial qualifying criteria and documentation requirements are met.

What is measurement by difference?
Measurement by difference is any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes. It results in the unmeasured volume absorbing all the measurement uncertainty and error associated with the measured volumes. (See Section 5.5)

Does measurement by difference apply to all types of reporting facilities?
No, measurement by difference in Section 5.5 only applies to proration type batteries within limits. Other facilities will be evaluated on a case-by-case basis upon application to the ERCB.

Section 6: Conventional Oil Measurement

Does double proration require special approval?
Yes, it will be reviewed on a case-by-case basis upon application to the ERCB.

Can crude oil be reported on a gas equivalent volume basis in a gas system on the PRA?
No, only condensate or other light hydrocarbon liquids are allowed to be reported on a gas equivalent volume basis in a gas system.

Do I have to report oil well testing volumes to the PRA?
Yes, and it must be reported as prorated production under an oil battery code. (See Section 6.2.2.1)

May I count the non-flowing hours as producing hours for an oil well using an on/off-type operating system, such as a plunger lift?
Yes, provided that the well is operated on a cyclical on/off basis. For reporting, however, the PRA limits the on/off cycle to less than a month because you cannot report production hours

without production volumes except in crude bitumen single-well batteries. The well(s) involved must have a PRA “OIL PUMP” well status. (See Section 6.4.1)

Is WATER reporting required at delivery points and LACT units?
The requirement is to report the water portion and the hydrocarbon portion of the total volume separately.

Section 7: Gas Proration Batteries

What is the frequency for proration testing a well in a proration battery?
Annually, unless stated otherwise in *Directive 017*.

What zones are allowed to be included in a SE Alberta shallow gas battery?
Gas wells that are located south of Township 31 and east of the 5th Meridian and produce from shallow gas zones, including coals and shales from the top of the Edmonton Group to the base of the Colorado Group in SE Alberta may be included in this type of battery under ERCB Commingling Order No. MU 7490. (See Section 7.2)

Section 8: Gas and Liquid Sampling and Analysis

What is the frequency of gas sampling and analysis for a well on GOR or for other facility types?
See Table 8.3 in Section 8.4. The frequency varies depending on the well/facility type.

Do I have to submit the sample analysis to the ERCB?
No, there is no requirement to submit the analysis under *Directive 017* for production operation purposes, just keep the analysis and submit upon request. However, *Directive 040* does have certain requirements for submission of some well test analyses.

What is the frequency for gas sampling for common pool exemptions if there is more than one zone commingled downhole?
Revert to Section 8.4 requirements even if there is prior exemption on individual pools, as there is no longer just one zone per well.

Section 9: Cross-Border Measurement

What are considered cross-border locations that require measurement?
Any facility receiving non-Alberta production from and/or delivering Alberta production to another jurisdiction, such as British Columbia or Saskatchewan or the National Energy Board (through its regulated facilities), either by trucking or pipeline, is considered a cross-border location where each jurisdictional production stream must be isolated and measured prior to commingling. (See Section 9.1)

What requirements should I adhere to when there are differences among the jurisdictions?
The most stringent requirements (e.g., in terms of frequency or accuracy) among the jurisdictions must be adhered to. (See Section 9.1)

Section 10: Trucked Liquids Measurement

Is an air eliminator required for a truck-in delivery point measurement using meters?
Yes, it is required with no grandfathering. (See Section 10.3.2)

Is it acceptable to use truck tickets to determine volumes received into a facility?
No, unless the ticket volumes are based on the required measurement for the fluid type received using meters, weight scales, or tank level measurement.

Section 11: Acid Gas and Sulphur Measurement

Is the new acid gas calculation from wet to dry basis grandfathered for existing plants?
No, this is a new procedure that is more accurate than the previous one in *Directive 046* and all facilities producing acid gas are required to implement this new procedure.

Do I need to have an acid gas injection wellhead measurement?
Yes, a meter is required for each acid gas well before injection at the well site (see Section 11.4.4.3).

Section 12: Heavy Oil Measurement

Which types of batteries can use the disposition equals production reporting methodology?
Only single-well batteries, group batteries, or administrative groupings (paper batteries) with a PRA well status fluid type code 17 (bitumen) may use the disposition equals production reporting methodology. (See Section 12.3.1.1)

Can individual single wells on the same lease be reported as part of an administrative grouping?
No, all wells must be on separate leases to be included in an administrative grouping. (See Section 12.3.1.2)

Section 13: Condensate and High Vapour Pressure Liquid Measurement

When do I have to report liquid condensate production at the well level to the PRA?
Liquid condensate production for a well must be reported on the PRA when the condensate is separated from the gas effluent at the first opportunity, either at the wellhead separator or at

the group separator of a proration system that does not send it to a gas facility for further processing. (See Section 13.3)

Section 14: Liquids Measurement

When do I have to calculate and report shrinkage due to blending hydrocarbon with different densities or flashing of light ends from hydrocarbon liquids?
If the hydrocarbon fluid densities differ by more than 40 kg/m^3, then you are required to calculate the blending shrinkage and report any volumes that cause the delivery point volumes to shrink by more than 0.1% and by more than the 0.1 m^3 reporting limit on the PRA. Flashing shrinkage must be determined if the added diluent volume is >2.0 m^3/day and/or >5.0% of total oil production (see Table 5.2 for details).

Section 15: Water Measurement

Do I need to have a water source wellhead measurement?
Yes, a meter is required for each water source well before commingling. (See Section 15.2.3)

Do I need to have a water injection or disposal wellhead measurement?
Yes, a meter is required for each water injection or disposal well before injection at the injection site. (See Section 15.2.4)

When do I have to report water of condensation (ABWC)?
For gas wells, water vapour must not be reported as production that is not condensed under wellhead separator conditions for single wells and gas groups, or at the group separator for proration wells (see Section 15). Any WATER disposition over and above the known source of water delivered into gas gathering systems or gas plants must be reported on the PRA as an “ABWC” receipt and total disposition (see Section 15.2.1.6). This applies when there are multiple single wells, gas groups, and/or other facilities tied into the facility with commingled water.