FAQs about Directive PNG017: Measurement Requirements for Oil and Gas Operations Revision 4

General

When does *Directive PNG017: Measurement Requirements for Oil and Gas Operations* (Directive PNG017) revision 4 come into effect?

Revision 4 of Directive PNG017 comes into effect on September 1, 2020.

Is it acceptable to report no gas production?

Generally, no. If after an engineering estimate has been completed for a well and gas production is proven to be less than 0.1 10^3m^3 *per month* you will be required to apply to the Ministry of Energy and Resources (ER) with documentation proving volumes are less than 0.1 10^3m^3 *per month* while remaining consistent with Guideline PNG034: Submission of Gas Oil Ratio Factor.

Where might I find information regarding measuring gas volumes?

For more information on when gas volumes should be metered or estimated, please see: Section 4.3.8 for non-heavy oil facilities and Section 12.2.2 for heavy oil facilities. Sound engineering estimation methods must be used for any estimated volumes. All documentation proving volumes must be kept for ER to review.

When does Directive PNG017 come into effect for Saskatchewan?

Directive PNG017 came into effect April 1, 2016. All operators must have implemented 100% of all new requirements pertaining to this Directive by April 1, 2021.

Which facilities are required to have a measurement schematic?

All facilities except for facility subtype 371 (gas testing battery) and subtype 381 (drilling and completing battery) are required to have a compliant measurement schematic. A compliant measurement schematic means the measurement schematic matches the actual facility layout and has all the required information as per Section 1.8 and 1.9 of Directive PNG017.

Does Directive PNG017 replace Guideline 23?

Yes. Guideline 17 and Guideline 23 are replaced by Directive PNG017 and are no longer in effect.

How can a company apply for a Measurement Exemption?

Applications may be submitted through the Integrated Resource Information System (IRIS). Information regarding submission of the required application form and associated documentation may be found at the link below.
https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/oil-and-gas-drilling-and-operations/measurement-requirements

Which measurement points are covered in this directive?

The requirements in this directive cover all measurement points required by *The Oil and Gas Conservation Act* and associated regulations for upstream petroleum facilities and some downstream pipeline operations, as well as those used for ER accounting and reporting purposes.

Does ER test, approve, or endorse measurement devices?

No, ER 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 PNG017 sets the base requirements for the oil and gas industry and any operator exceeding these requirements is considered to have met the requirements.

If my facility meets Measurement Canada measurement standards is the facility compliant with Directive PNG017?

Yes, if the facility meets Measurement Canada standards then it meets Directive PNG017 standards. If a facility has received special approvals from Measurement Canada regarding calibration and proving, such documentation must be available upon request by ER.

Where do I have to install delivery point measurement?

Delivery point measurement is required at cross-border facility dispositions (sending volumes from Saskatchewan to another province or state) and the following locations within the upstream oil and gas systems: trucked-in receipts, pipeline receipts, sales, and lease automatic custody transfer points (LACT). See Sections 1.6.2 to 1.6.20 for oil and gas delivery points. For example, if Battery A is delivering into Battery B, Battery B is required to have delivery point measurement whether or not ownership of Battery A and B are the same. For example, if Battery C is delivering load oil into Battery B, then Battery C is responsible for delivery point measurement.

Does a gas storage facility have to meet the requirements in this directive?

Yes, a gas storage facility is required to meet the standards of this directive.

Is it a requirement to have injection wellhead measurement for all injected products?

Yes. The requirement is for separate measurement of all product types at each wellhead before injection. See Directive PNG017, Sections 1.6.4, 1.7.3, 11.4.6.3, and 15.2.4.

Section 1: Standards of Accuracy

What are the standards of accuracy?

Standards of accuracy 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).

Do I have to prove to ER that I have met the standards of accuracy for every measurement point?

No. If you follow the requirements, procedures, and industry standards stated in Directive PNG017, then you are considered to have met the standards of accuracy.

Section 2: Calibration and Proving

What steps are required to calibrate a differential-type meter, such as an orifice meter?
Section 2.3.5 of this directive sets out the requirements for calibrating an orifice meter. These requirements may 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," would not be considered clear.

What is the calibration frequency for a gas rotary or turbine meter and the related instrumentation?

The calibration frequency is annually for a pressure or temperature transducer. However, if it is at a delivery point or in a gas plant, then the frequency is semi-annually. The rotary or turbine meter itself must be calibrated once every seven years. (See Section 2.3.4).

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?

It is only permissible to use the internal diagnostics of a meter 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 2.3.4, items 8 for gas meters and 2.4.2 for liquid meters).

When can an oil meter be bench proved?

An oil meter can be bench proved only if the oil rate through the meter is less than 2 m^3 per day as per Section 2.5.1.1. If the oil volumes through the meter is greater than 2 m^3 per day then the meter must be proved in line with a prover.

Do I need to install proving taps at my facility?

Possibly. If the meter can be bench proven as per Section 2.5.1.1 (i.e. flow of oil through the meter is less than 2 m^3/d) then no proving taps are required. However, if the flow rate of oil through the meter is at or above 2 m^3/d volumes inline proving is required and therefore proving taps are required.

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

Are the proration factors enforceable?

Yes, with the implementation of the Enhanced Production Audit Program (EPAP) operators are required to monitor their monthly Compliance Assessment Indicators (CAIs) which include proration and allocation factors to determine if these factors are outside the tolerance. If the operator does not investigate why these factors are outside of the acceptable ranges, then enforcement could be applied as per Section 13.6 of *Directive PNG076.*

Which facilities are not allowed to report a metering difference?

Single well batteries, group batteries, proration batteries, and custom treaters are not allowed to report metering difference for gas and water.

Which facilities are allowed to report an oil metering difference?

No metering difference (or in Petrinex terminology "Imbalance") is allowed for oil. All facilities must balance the oil stream at the facility.

Section 4: Gas Measurement

When do the changes to the fuel, flare and vent definitions come into effect in Saskatchewan?

As of January 1, 2020, operators must report the fuel gas, vent gas, and flare gas based on the definitions listed in the current version of Directive PNG017 Appendix 2.

Are fugitive emissions required to be reported in Petrinex?

Yes, when a fugitive emission is found by either the operator or by ER staff, operators are required to estimate and report the amount of gas released as VENT in Petrinex, until the fugitive emissions is eliminated as per Section 4.2.

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 continuously metered wells together with proration tested wells, or some wells may have effluent (wet gas) measurement, while others do not.

What if a facility is generating volumetric errors but there is not enough gas to report?

If a facility does not have enough gas production to be reported then the operator of the facility can apply to ER to have the GOR factor for the wells submitted in Petrinex, which will waive the volumetrics errors in Petrinex for 15 months. To apply for this waiver of errors see Guideline PNG034: Submission of Gas Oil Ratio Factor. This application must be submitted every 15 months given operators are required, as per Section 4.3.8.5, to determine the GOR factor annually.

When is metering of gas volumes required?

All non-heavy oil associated gas (gas produced from a non-heavy oil well) must be metered when the gas stream related to production, vented gas, flared gas, and fuel gas is above 0.50 $10^3m^3/d$. For gas streams related to production, vent gas, flare gas, and fuel gas below 0.50 $10^3m^3/d$, operators must use an acceptable engineering estimation method. Note that operators are allowed to estimate up to 0.50 $10^3m^3/d$ and meter the remaining volumes over the 0.50 $10^3m^3/d$ threshold.

What is an acceptable engineering estimate method for gas production?

Depending on the type of non-heavy oil facility, there are many options available:

- For single well batteries and group batteries (as per Section 4.2.1 and 4.3.8.2), a well level GOR factor (which may need to include the Gas in Solution) may be determined or on initial startup of the well an hourly rate may be determined. If gas in solution (GIS) is not included, then the GIS must be estimated using acceptable engineering estimation methods listed in Section 4.3.8.1. Acceptable methods to determine a GOR Factor and Hourly Rate can be found in Section 4.3.8.5 of Directive PNG017.

- For non-heavy crude oil multiwell proration batteries (as per Section 4.2.1), a well level GOR factor or a battery level GOR factor may be used to determine the gas production volumes. Methods allowed to be used to determine a well level GOR factor may be found in Section 4.3.8.5. Methods allowed to be used to determine a battery level GOR factor may be found in Section 4.3.8.3.

What is a gas-in-solution factor and when is it needed?

A gas in solution (GIS) factor is a factor that is used to determine the gas remaining in the emulsion, water and/or oil. This factor can be determined by using one of the methods outlined in Section 4.3.8.1. A GIS factor needs to be determined if the GOR factor does not include the gas in solution or if a gas well test does not include the GIS factor.

Do I have to apply to use a GOR for gas production determination at an oil well?

No. If you meet the requirements in Section 4.3.6 for non-heavy oil or Section 12.2.2 for heavy crude oil application is not required.

Which facilities require VENT gas measurement?

Any non-heavy oil facility, such as a well site, oil satellite, battery, or individual compressor site where venting is occurring, including fugitive emissions, must measure and report VENT GAS. Depending on the volume of gas it can either be estimated (below 0.50 $10^3m^3/d$) or metered (at or above 0.50 $10^3m^3/d$). (See Section 1.6.3.6)hat types of gas does VENT GAS include?
As of January 1, 2020, as per Appendix 2 in Directive PNG017, VENT GAS is uncombusted gas that is released to the atmosphere at upstream oil and gas operations and includes:

- Blanket gas;
- Facility upsets and emergency shutdowns;
- Fugitive emissions;
- Gas from compressor seals, starters, and blowdowns;
- Gas from dehydrator still columns;
- Gas from production tanks, not including methanol and chemical tanks;
- Gas produced during well completions;

- Gas produced during well unloading volumes;
- Gas released during pigging operations;
- Gas used to operator pneumatic devices; and
- Waste Gas.

How to determine the volume for VENT GAS?

Guideline PNG035: Estimating Venting and Fugitive Emissions provides estimation methods for determining vent gas volumes.

Which facilities require FLARE GAS measurement?

Any non-heavy oil facility, such as a well site, oil satellite, or battery where flaring is occurring must be measured and reported as FLARE GAS. Depending on the volume of gas it can either be estimated (below 0.50 $10^3m^3/d$) or metered (at or above 0.50 $10^3m^3/d$). (See Section 1.6.3.6)

Which types of gas does FLARE GAS include?

As of January 1, 2020, as per Appendix 2 in Directive PNG017, FLARE GAS is gas that is combusted in a flare or incinerator at upstream oil and gas operations. Types of gas, if combusted in a flare or incinerator, that must be reported as flare gas include the following:

- Acid gas (routine and non-routine);
- Blanket gas, purge gas, or sweep gas;
- Dilution and make-up gas added to a flare gas stream before flaring or incineration;
- Gas from dehydrator still columns;
- Gas produced during well completions;
- Gas produced during well unloading operations;
- Gas that is flared or incinerated as a result of equipment failures or plant upsets;
- Gas used to operate pneumatic devices (instruments, pumps and compressors starters);
- Pilot gas; and
- Waste gas

Which facilities require FUEL measurement?

Any non-heavy oil facility, such as a well site, oil satellite, or battery, where fuel is being used it must be measured and reported as FUEL GAS. Depending on the volume of gas it can either be estimated (below 0.5 $10^3m^3/d$) or metered (above 0.5 $10^3m^3/d$). (See Section 1.6.3.5)

Which types of gas does FUEL GAS include?

As of January 1, 2020, as per Appendix 2 in Directive PNG017, FUEL GAS is gas that is combusted and the released energy is used in upstream oil and gas operations. Types of gas that must be reported as fuel gas include gas burned by the following:

- Catalytic heaters and other building heaters;
- Engines;
- Line heaters;
- Process vessel burners;
- Sulphur recovery unit reaction furnace; and
- Thermoelectic generators.

How do I report dilution, purge, or fuel gas that has been added to a flare system?

As of January 1, 2020, any fuel, purge, or dilution gas added to the flare must be reported as part of the flared volumes. (See Sections 1.6.3.8 and 4.3.6)

Do I have to report a gas well's pre-production testing volumes into Petrinex?

Yes. Volumetric reporting must be done under a gas test battery (facility subtype 371) if the volumes are flared or vented.

Do I have to report flaring during drilling and completing of a well into Petrinex?

Yes. Volumetric reporting must be done under a Drilling and Completing Battery (facility subtype 381) and using the activity of FLARE.

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 4.2.4 for exemptions).

Is gas measurement required at a gas plant outlet?

Yes, if the gas is for disposition. For the stream that is measured by the gas receiver's measurement point, the plant outlet meter is intended for checking or reference only. Gas measurement at a gas plant outlet is a requirement if there are other gas streams tied in between the plant and the gas receiver's measurement point. (See Section 4.3.1)

Do I have to measure the dilution gas used when flaring acid gas?

Yes. It is a requirement to measure dilution gas regardless of the volume.

Can I extend the chart cycle?

Yes, chart cycles may be extended beyond the required time period as per Section 5.3 and without regulatory approval if the initial qualifying criteria in Section 5.3.1.1 is met.

Does the static pressure tap for orifice measurement have to be tied to one of the differential taps?

Yes. It must be tied from either the upstream or downstream tap in accordance with American Gas Association Report #3.

Do I have to use Electric Flow Measurement (EFM) for any kind of an on/off flow production, such as a plunger lift system? No, unless you are implementing the exemption in Section 5.3 for extended chart cycle or are ordered to use an EFM by ER, however EFM is recommended for better accuracy.

Is there a maximum sensing line length requirement?

No, there is no maximum sensing line length. 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?

No. There are to be full port valves installed at all measurement points to eliminate restriction of the sensing line diameter at delivery, group, or sales measurement points. (See Section 4.3.4.1)

Do I have to install self-draining differential pressure sensing lines?

Yes. There must be self-draining differential sensing lines installed at every measurement point. (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. There must not be any drip pots installed at delivery, group, or sales 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.

Which types of gas batteries can use the disposition equals production reporting methodology?

For gas batteries, only certain single-well batteries and group batteries, with facility subtype 351 and 362 may use the disposition equal production reporting methodology if the well(s) that produce ≤ 2.0 m^3/d of total liquid (i.e., condensate and water) and direct condensate and water production to lease tanks or to a single emulsion tank, see Section 4.2.2.1 and 4.2.2.2.

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 ER through IRIS.

If a facility requires an oil measurement by difference approval as per Section 5.5.2.1, when is it required to be approved by?

For all facilities licensed before April 1, 2016, operators have until April 1, 2021 to have all measurement exemption applications approved. For a facility licensed after April 1, 2016, when a facility is routinely over the R-ratio of 1.0 then an approved oil measurement by difference application is required.

How do I apply for a measurement exemption application?

Operators can apply through IRIS, for any deviation from base requirements. The application must include the measurement exemption application form and all additional supporting documentation listed in the form. Information regarding the measurement exemption application can be found at https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/oil-and-gas-licensing-operations-and-requirements/oil-and-gas-drilling-and-operations/measurement-requirements/apply-for-a-measurement-exemption.

Section 6: Non-Heavy Oil Measurement

What is non-heavy oil?

Non-Heavy oil is considered any oil with a crude oil density of less than 920 kg/m^3.

Does double proration require special approval?

No. However it is recommended that all operators trucking volumes into the double prorated facility be notified that double proration methodology is being utilized at the receiving facility.

Can crude oil be reported on a gas equivalent volume basis in a gas system on Petrinex?

No. Only condensate is allowed to be reported on a gas equivalent volume basis.

Do I have to report oil well testing volumes to Petrinex?

Yes. Volumes, as a result of oil well testing, must be reported as prorated production under an oil battery facility ID in Petrinex. (See Section 6.2.2)

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.

What is the frequency for proration testing of a well in a proration battery?

As per Section 6.4.4, the frequency of proration well testing is dependent on the rate of oil production.

Section 7: Gas Proration Batteries

What zones are allowed to be included in a SW Saskatchewan shallow gas battery?

Gas wells that are completed within the zones, including coals and shales, from the base of the Glacial Drift to the base of the Upper Cretaceous. The production from two or more of these zones without segregation in the wellbore requires prior commingled production approval from ER. (See Section 7.2)

Section 8: Gas and Liquid Sampling and Analysis

What is the frequency of gas sampling and analysis for a well or facility?

See Table 8.3 in Section 8.4. The frequency varies depending on the well or facility type.

Do I have to submit the sample analysis to ER?

Yes, operators are required to submit the sample analysis under *The Oil and Gas Conservation Regulations, 2012* every time an analysis is completed whether or not the analysis is for the well or facility. Operators will submit their analyses through IRIS.

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 for individual pools, since there is no longer just one zone per well.

Is an oil analysis required for a new oil well?

With the release of revision 3 of Directive PNG017, an oil analysis is no longer required to be conducted for new oil wells. Note, if an analysis is conducted then the analysis MUST be submitted to IRIS within 30 days of the sample date as per *Directive PNG013: Well Data Submission Requirements*. ER still has the authority to request an operator to conduct an oil analysis at any time as per *The Oil and Gas Conservation Regulations, 2012.*

Section 9: Cross-Border Measurement

What are considered cross-border locations that require measurement?

Any facility receiving non-Saskatchewan production from or delivering Saskatchewan production to another jurisdiction, such as Alberta or Manitoba, either by truck or pipeline, is considered a cross-border location where each jurisdictional product 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, an air eliminator is required for a truck-in delivery point measurement that uses meters. (See Section 10.3.1)

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

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 11.4.6.3).

Section 12: Heavy Oil Measurement

What types of facilities does Section 12 apply to?

Section 12 applies to operators of heavy oil facilities; wells that produce oil with a density greater than 920 kg/m^3 must follow the procedures outlined in this section. This section also applies to thermal in-situ operations.

Which types of batteries can use the disposition equals production reporting methodology?

For oil batteries, only paper batteries, single-well batteries, and group batteries with a facility subtype of 313, 325 and 326 may use the disposition equals production reporting methodology, see Section 12.2.1. Note that if any volumes are received into the facility the facility no longer qualifies for use of disposition equals production.

When is metering of gas volumes required?

All heavy oil associated gas (gas produced from a heavy oil well) must be metered when the gas stream related to production, vented gas and flared gas is above 2.0 10^3m^3/d. For gas streams related to production, vent gas, flare gas below 2.0 10^3m^3/d, operators must use an acceptable engineering estimation method. For gas streams related to fuel gas volumes must be metered over 0.5 103m3/d. Note, operators are allowed to estimate up to 2.0 10^3m^3/d, or 0.5 10^3m^3/d and meter the remaining volumes over the 2.0 10^3m^3/d or 0.5 10^3m^3/d threshold.

What is an acceptable engineering estimate method for gas production?

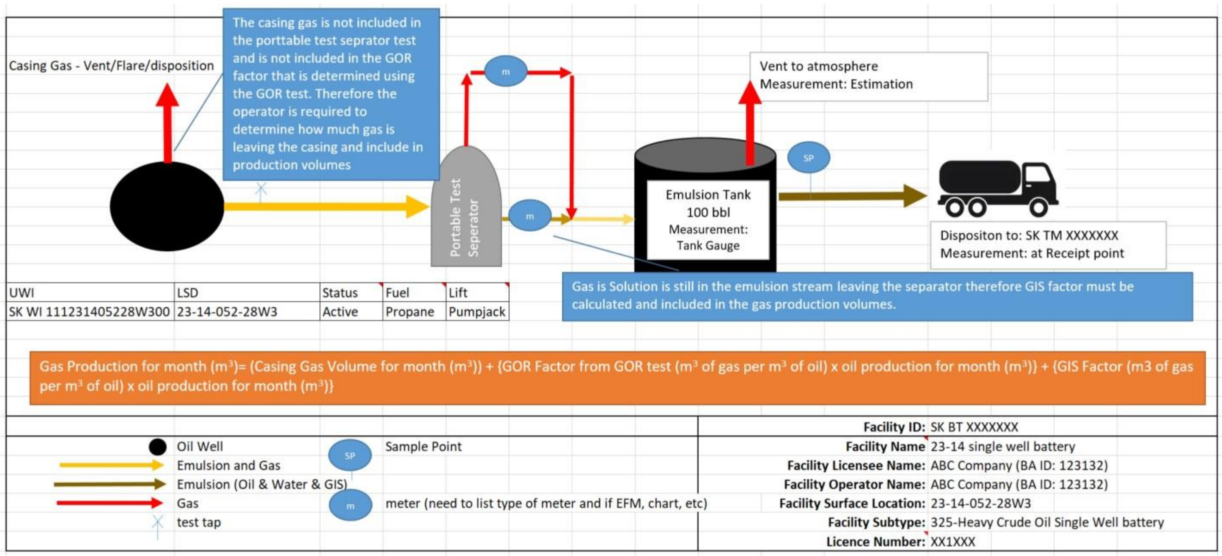
Depending on the type of heavy oil facility, there are many options available:

- For single well batteries and group batteries (as per Section 12.2.2.1), a well level GOR factor (which may need to include the Gas in Solution) can be determined or on initial startup of the well then an hourly rate can be determined. Allowable methods to determine a GOR Factor or Hourly Rate can be found in Section 12.2.3 of Directive PNG017.
- For heavy crude oil multiwell proration batteries (as per Section 12.2.2.2), a well level GOR factor or a battery level GOR factor can be used to determine the gas production volumes. Methods allowed to be used to determine a well level GOR factor can be found in Section 12.2.3. Methods allowed to be used to determine a battery level GOR factor may be found in Section 12.2.2.2.

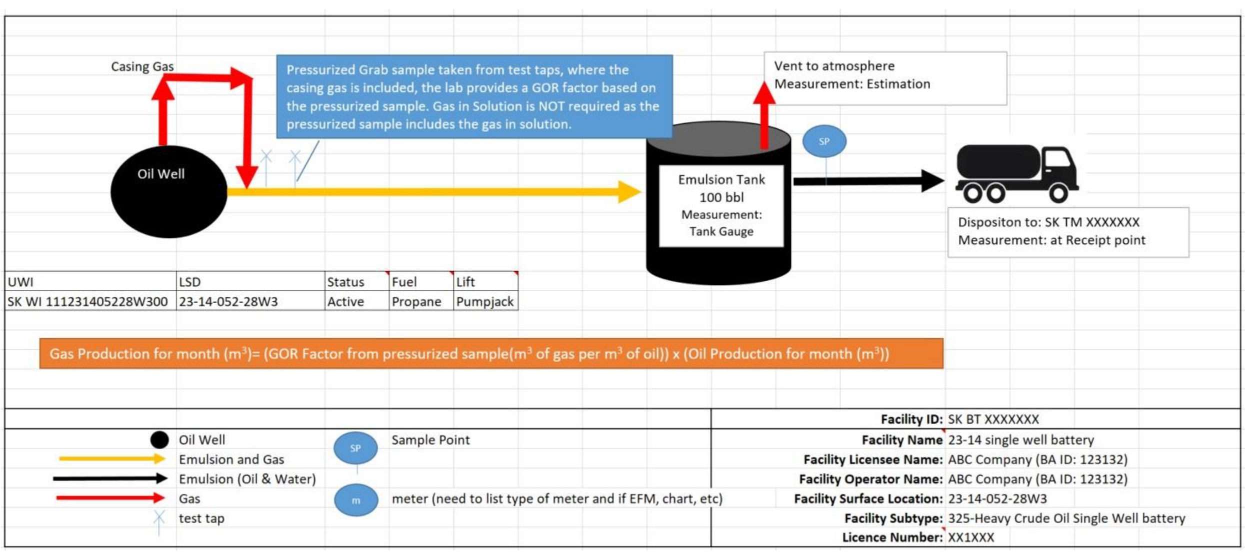
What is a gas in solution factor and when is it needed?

A gas in solution (GIS) factor is a factor that is used to determine the gas remaining in the emulsion, water and/or oil. This factor can be determined by using one of the methods outlined in Section 12.2.3.3 Method for Determining Gas in Solution (GIS) Factor. A GIS factor needs to be determined if the GOR factor does not include the gas in solution or if a gas well test does not include the GIS factor.

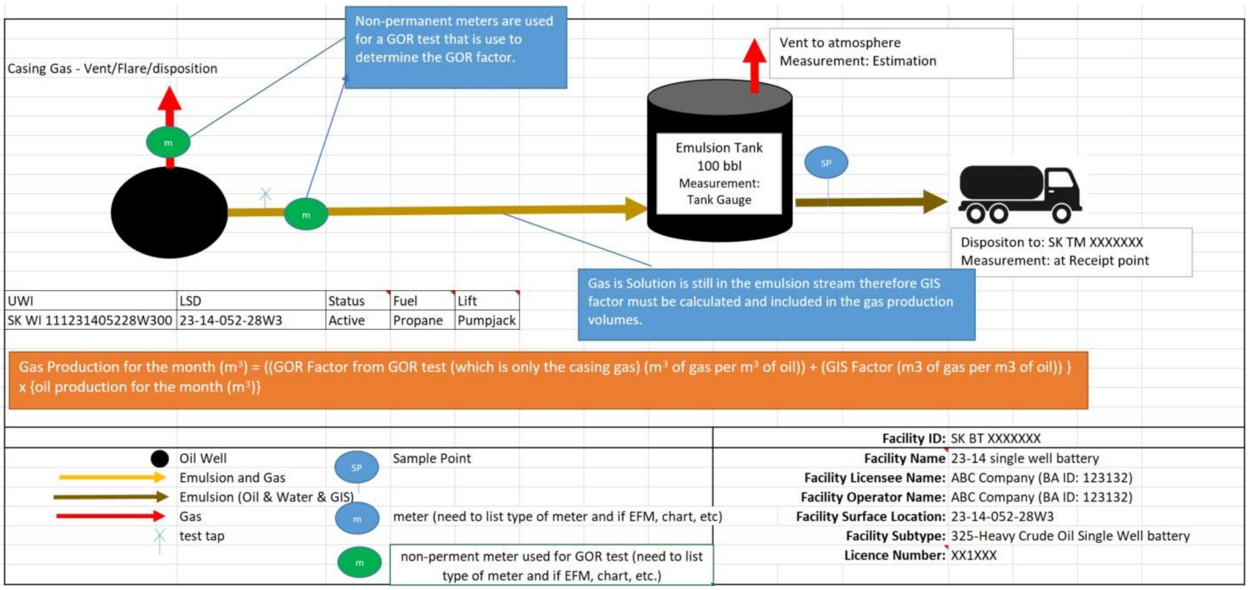
Example 1: GIS is required



Example 2: GIS not required



Example 3: GIS required



How do I determine gas production volumes during the initial flowback of the well?

The operator must determine the gas production volume the same month as the well is put on production. If the gas production is not dependent on oil production due to the flow back of drilling fluids, then an hourly rate can be determined for the gas production until the well is stabilized. The hourly rate must be determined on a monthly basis and as per Section 12.2.3.

How often does the GOR Factor and GIS Factor need to be updated?

The GOR Factor must be updated (re-tested or another pressurized sample completed) based on the gas production rate of the well as per Table 12.1. For gas rates less than or equal to 1.0 $10^3m^3/d$ the GOR factor must be updated annually; for gas rates greater than 2.0 $10^3m^3/d$ the GOR factor must be updated semi-annually.

Can an exemption be applied for to extend the period for the frequency of determining the GOR Factor?

At this time ER is not granting extensions to the frequency of determining the GOR Factor.

What facilities require VENT gas measurement?

Any heavy oil facility, such as a well site, oil satellite, battery, or individual compressor site where venting is occurring including fugitive emissions must measure and report VENT GAS. Depending on the volume of gas it can either be estimated (below 2.0 $10^3m^3/d$) or metered (above 2.0 $10^3m^3/d$). (See Section 1.7.4 and Section 12.2.2.2)

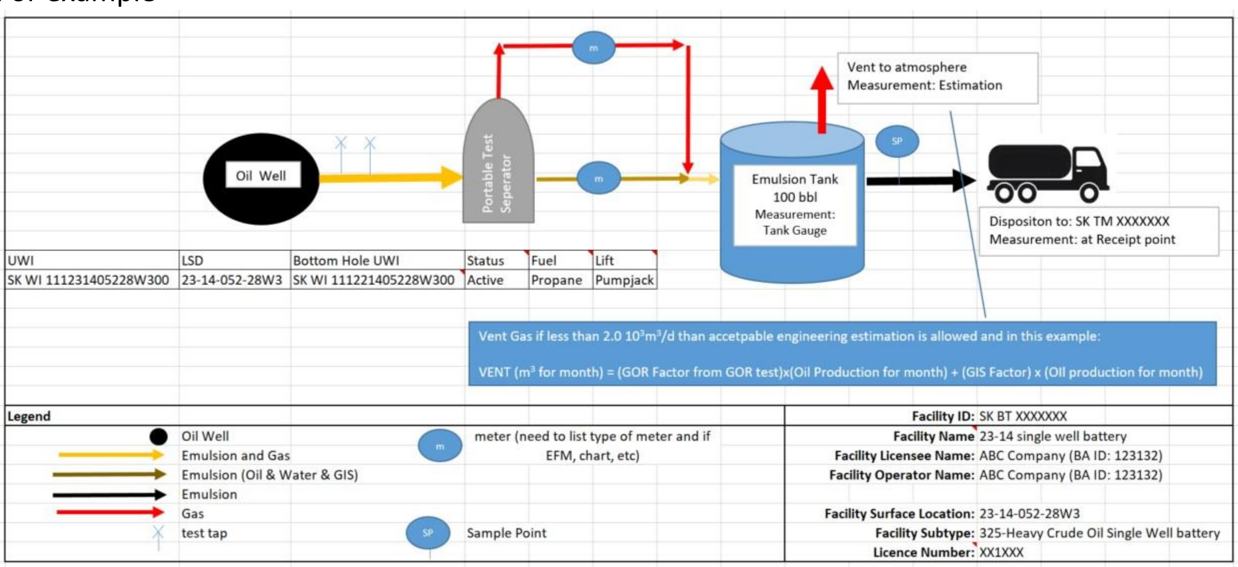
Which types of gas does VENT GAS include?

As of January 1, 2020, as per Appendix 2 in Directive PNG017, VENT GAS is uncombusted gas that is released to the atmosphere at upstream oil and gas operations and includes:

- Blanket gas;
- Facility upsets and emergency shutdowns;
- Fugitive emissions;
- Gas from compressor seals, starters, and blowdowns;
- Gas from dehydrator still columns;
- Gas from production tanks, not including methanol and chemical tanks;
- Gas produced during well completions;
- Gas produced during well unloading volumes;
- Gas released during pigging operations;
- Gas used to operator pneumatic devices; and
- Waste Gas.

How do I determine the volume for VENT GAS?

Guideline PNG035: Estimating Venting and Fugitive Emissions provides estimation methods for determining vent gas volumes depending on the operation that is occurring to cause the venting. For example



Do you have to report the venting of casing gas into Petrinex?

Yes, all associated gas (gas produced from an oil well) and non-associated gas must be measured and reported. However, depending on the volume of gas it can either be estimated (below 2.0 $10^3m^3/d$ for non-heavy facilities) or metered (above 2.0 $10^3m^3/d$ for non-heavy facilities). Methods estimating gas volumes can be found in *Directive PNG017* Section 12.2.2 and for additional information see *Guideline PNG035: Estimating Venting and Fugitive*

Emissions. Reporting in Petrinex 0.1 10^3m^3 for the month is not acceptable unless there is an acceptable engineering estimation method to prove that this is the actual volume. The calculation procedure used to determine the estimated volumes must be kept for ER to review at any time.

What facilities require FLARE gas measurement?

Any heavy oil facility, such as a well site, oil satellite, or battery where flaring is occurring must measure and report FLARE GAS. Depending on the volume of gas it can either be estimated (below 2.0 10^3m^3/d) or metered (above 2.0 10^3m^3/d). (See Section 1.7.4 and Section 12.2.2.2)

Which types of gas does FLARE GAS include?

As of January 1, 2020, as per Appendix 2 in Directive PNG017, FLARE GAS is gas that is combusted in a flare or incinerator at upstream oil and gas operations. Types of gas, if combusted in a flare or incinerator, that must be reported as flare gas include the following:

- Acid gas (routine and non-routine);
- Blanket gas, purge gas, or sweep gas;
- Dilution and make-up gas added to a flare gas stream before flaring or incineration;
- Gas from dehydrator still columns;
- Gas produced during well completions;
- Gas produced during well unloading operations;
- Gas that is flared or incinerated as a result of equipment failures or plant upsets;
- Gas used to operate pneumatic devices (instruments, pumps and compressors starters);
- Pilot gas; and
- Waste gas

Which facilities require FUEL measurement?

Any heavy oil facility, such as a well site, oil satellite, or battery, where fuel usage is occurring must measure and report FUEL GAS. Depending on the volume of gas it can either be estimated (at or below 0.5 10^3m^3/d) or metered (above 0.5 10^3m^3/d). (See Section 1.7.4 and Section 12.2.2.2)

Which types of gas does FUEL GAS include?

As of January 1, 2020, as per Appendix 2 in Directive PNG017, FLARE GAS is gas that is combusted and the released energy is used in upstream oil and gas operations. Types of gas that must be reported as fuel gas include gas burned by the following:

- Catalytic heaters and other building heaters;

- Engines;
- Line heaters;
- Process vessel burners;
- Sulphur recovery unit reaction furnace; and
- Thermoelectic generators.

Government of Saskatchewan

Section 13: Condensate and High Vapour Pressure Liquid Measurement

When do I have to report liquid condensate production at the well level to Petrinex?

Liquid condensate production for a well must be reported to Petrinex 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, and does not get recombined with gas production (See Section 13.1.2). Note, Saskatchewan requirements differ from Alberta reporting volumes for condensate.

Hydrocarbon liquids with density ≤ 780 kg/m^3 produced and separated from a gas well or at the group measurement points of multiwell gas proration or effluent proration batteries and trucked for sale, or for further processing, are considered field condensate and must be reported as a liquid COND volume at the well level. Condensate production cannot be reported for an oil well.

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/m3, 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 m3 reporting limit into Petrinex.
Appendix 7 provides a blending shrinkage calculation example. Flashing shrinkage must be determined if the added diluent volume is >2.0 m3/day and/or >5.0% of total oil production (See Table 5.6 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 the volumes with water or fluids from other sources. (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 condensation (SKWC)?

For gas wells, water vapour that is not condensed under wellhead separator conditions for single wells and gas groups, or at the group separator for proration wells must not be reported as production (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 Petrinex as receipt of WATER from an “SKWC” receipt (See Section 15.2.1.6).