



***Manual 001: Facility and Well
Site Inspections***

Section B: Oil Facilities

July 2011

Disclaimer

The following information is provided for guidance and summary purposes only and is not an exhaustive description of ERCB requirements relating to a given topic or subject area.

Operators and licensees must at all times comply with and should consult all applicable ERCB requirements before undertaking any activity.

Introduction

- *Manual 001: Facility and Well Site Inspections* is a resource document for ERCB personnel.
- Purpose is to ensure that facilities and well sites are inspected consistently.
- Designed to highlight the most prevalent noncompliances encountered during routine surveillance and provide references to the ERCB requirements for the identified deficiencies.
- Industry may also use this manual to become familiar with ERCB inspections and as a guide for their own compliance management systems.

Introduction Cont.

- *Manual 001* is a consolidation of the 2005 rescinded editions of
 - *Directive 063: Requirements and Procedures for Oilfield Waste Management Facilities, and*
 - *Directive 064: Requirements and Procedures for Facilities.*
- New and updated regulatory requirements since 2005 have been incorporated into this document.
- *Manual 001* is effective as of January 1, 2011.
- The ERCB is committed to continuous improvement and will update this manual as needed to ensure that it continues to reflect current regulatory requirements.

How to use Manual 001

Manual #	Result	Description
1.1.5.5	High Risk	No gas delivery point (sales) measurement. [OGCR 7.004, 14.040; Directive 017 (1.7.2(i)), (4.1), (9.3), (Appendix 3)]

- Manual # :
 - number used by the Field Inspection System (FIS) and the Digital Data Submission (DDS) system to identify inspection items in the database (Does not refer to sections in ERCB Directives or Regulations)
- Result:
 - predetermined risk rating associated with the noncompliance based on health and safety, environmental impact, conservation, and stakeholder confidence in the regulatory process
- Description:
 - the noncompliance statement with hyperlinked references to the opening page of relevant regulatory documents

Section B, (1.1): Gas Measurement

- All gas produced, injected, flared/vented, fuel, and delivery (sales), gas must be accurately measured/estimated.
- Meter design, installation, operation, maintenance, calibration/verification, and well testing must be conducted in accordance with
 - ERCB *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations (Directive 017)*, and
 - the *Oil and Gas Conservation Regulations (OGCR)*.

Section B, (1.1): Gas Measurement

- Gas meter calibration frequency:
 - within the first calendar month of operation of a new meter
 - immediately (by the end of the calendar month) following service or repairs to the meter
 - semiannually if the meter is used in a gas plant or for sales/delivery point (royalty trigger points)
 - annually for all other meters
- Meters (rotary or turbine) with internal moving parts must be proved at a frequency of once every 7 years following an initial proving prior to installation.
- Meter calibration/proving tag or detailed report must be attached to the meter.

Section B, (1.1): Gas Measurement

Gas Oil Ratio (GOR) or hourly rate:

- GOR or hourly rate gas estimation can be used instead of measurement when:

Conventional Oil:

- when the gas production volume is $\leq 0.5 \times 10^3 \text{m}^3/\text{d}$ at any given measurement/disposition point

Heavy Oil:

- if gas production per well or gas production rates at the point of collection is $< 2.0 \times 10^3 \text{m}^3/\text{d}$

- No specific approval is required from the ERCB.

Section B, (1.1): Gas Measurement

GOR testing frequency:

Conventional Oil:

- annual 24 hour test

Heavy Oil:

Gas rate ($10^3\text{m}^3/\text{d}$)	Test frequency
≤ 0.1	once every 3 years
> 0.1 but ≤ 1.0	annually
> 1.0 but < 2.0	semi-annually

Section B, (1.1): Gas Measurement

Circular Chart Recorders

- Drive/Multi Day Charts used appropriately
- recorder, sensing lines, and piping suitably winterized to prevent freezing
- pressure sensing lines must be self-draining
- chart information recorded:
 - gas stream being metered
 - measurement devices
 - measurement inputs, times, and events
 - meter location
 - date and on off chart times to nearest quarter hour
 - orifice plate and line size
 - gas temperature

* For further information see *Directive 017* or the *OGCR*.

Section B, (1.1): Gas Measurement

Gas Temperature Reading Frequency

Min temp reading frequency	Criteria or Events
Continuous	Sales/Delivery points and/or EFM devices
Daily	$> 16.9 \times 10^3 \text{m}^3/\text{d}$
Weekly	$\leq 16.9 \times 10^3 \text{m}^3/\text{d}$
Daily	a) Production (proration) volume testing b) Nonroutine or emergency flaring/venting

- Temperature-measuring element must be installed near the meter such that it will sense the flowing gas stream temperature. Licensees cannot use surface temperature of the piping or a thermo well location where there is normally no flow.

Section B, (1.1): Gas Measurement

- Fuel/Flare/Vent gas must be measured if $>500 \text{ m}^3/\text{day}$.
- Fuel/Flare/Vent gas can be estimated if $<500 \text{ m}^3/\text{day}$.
- All required gas measurement must be reported on the Petroleum Registry of Alberta in accordance with ERCB *Directive 007* and *Directive 017*.

Section B, (1.2): Hydrocarbon Liquids Measurement

- All hydrocarbon liquid production and delivery (sales) must be accurately measured/estimated.
- Measurement by meter, tank gauging, or weigh scale.
- Meter design, installation, operation, maintenance, calibration/verification, and well testing must be conducted in accordance with
 - *ERCB Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*, and
 - *the Oil and Gas Conservation Regulations*.

Section B, (1.2): Hydrocarbon Liquids Measurement

- Calibration/Proving Requirements

Meter application	Fluid type	Proving frequency
Wellhead, group, injection	Test oil, test emulsion, live condensate, water	Annually
Gas plant, cross-border	Live condensate, NGL, LPG	Semiannually
Delivery point, LACT	Oil, condensate, live condensate, NGL, LPG Monthly	Monthly (see exceptions in Directive 017)

A new hydrocarbon meter must be proved within the first calendar month of operation or immediately following any repairs being conducted on the meter or any changes to the meter installation.

A tag or label must be attached to the meter with meter serial number, date of the proving, type of prover/master meter used, and average meter factor.

Section B, (1.2): Hydrocarbon Liquids Measurement

Exceptions:

- If volume measured by a delivery point meter is $\leq 100 \text{ m}^3/\text{d}$, the proving frequency may be extended to quarterly (attached tag must indicate meter measures $\leq 100 \text{ m}^3/\text{d}$).
- If meter factor for delivery point meters is within 0.5% of previous factor for three consecutive months, the proving frequency may be extended to quarterly (attached tag must indicate meter has had consistent meter factors and is on a quarterly proving frequency).

Section B, (1.2): Hydrocarbon Liquids Measurement

- Live oil meters may be removed from service and proved in meter shop if
 - used to measure test volumes of conventional oil/emulsion, the average flow of all the wells tested must be $\leq 2 \text{ m}^3/\text{d}$ and no well may exceed $4 \text{ m}^3/\text{d}$
 - any meter used to measure test volumes of heavy oil/emulsion (density $> 920 \text{ kg/m}^3$) or crude bitumen
- Meter must be installed upstream of a snap acting control/dump valve, if present.

Section B, (1.2): Hydrocarbon Liquids Measurement

Using Tank Gauging for Oil Measurement

- Automatic tank gauge devices to indicate fluid levels in tanks for delivery point measurement (such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline) must be calibrated on site within first month of operation and monthly thereafter.
- The specific tanks used for tank gauging for delivery point measurement must be calibrated on site within first month of operation and any time the tank is damaged or altered.
- The calibration must result in the creation of a gauge table for each tank, which must then be used in conjunction with tank gauge readings to determine volumes.

Section B, (1.2): Hydrocarbon Liquids Measurement

Weigh scales

- Used to measure oil/water emulsion and clean oil receipts must be tested for accuracy as follows:
 - monthly,
 - immediately (by the end of the calendar month) following any incident which scale may have been damaged,
 - immediately (by the end of the calendar month) following any changes/modifications made to the scale.
- If volume is $<100 \text{ m}^3/\text{d}$, frequency may be extended to quarterly (would revert back to monthly if scale begins measuring $>100 \text{ m}^3/\text{d}$).
- If scale is found to not require calibration for three consecutive months, frequency may be extended to quarterly (revert back to monthly when test determines scale needs calibration).
- Density and volumes of oil, water, and sediment in the emulsion must be determined.

Section B, (1.3): Water/Other Measurement

- All water production, injection, disposal, and delivery must be accurately measured/estimated.
- Meter design, installation, operation, maintenance, calibration/verification, and well testing must be conducted in accordance with
 - ERCB *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*, and
 - the *Oil and Gas Conservation Regulations*.

Section B, (1.3): Water/Other Measurement

- Where a water meter is used to measure water production, the licensee shall calibrate the meter:
 - within the first three months of operation,
 - immediately following any repairs to the meter,
 - annually since the last calibration or recalibration.
- The licensee must attach to the meter an indestructible tag or label which has the date of last calibration, the meter serial number, and the meter factor.

Section B, (1.3): Water/Other Measurement

- Where the metering water is required licensees shall:
 - install the meter upstream from a snap acting control valve that will maintain a reasonably uniform flow rate through the meter
 - if prover taps are installed they shall be located downstream from the control valve

Section B, (1.3): Water/Other Measurement

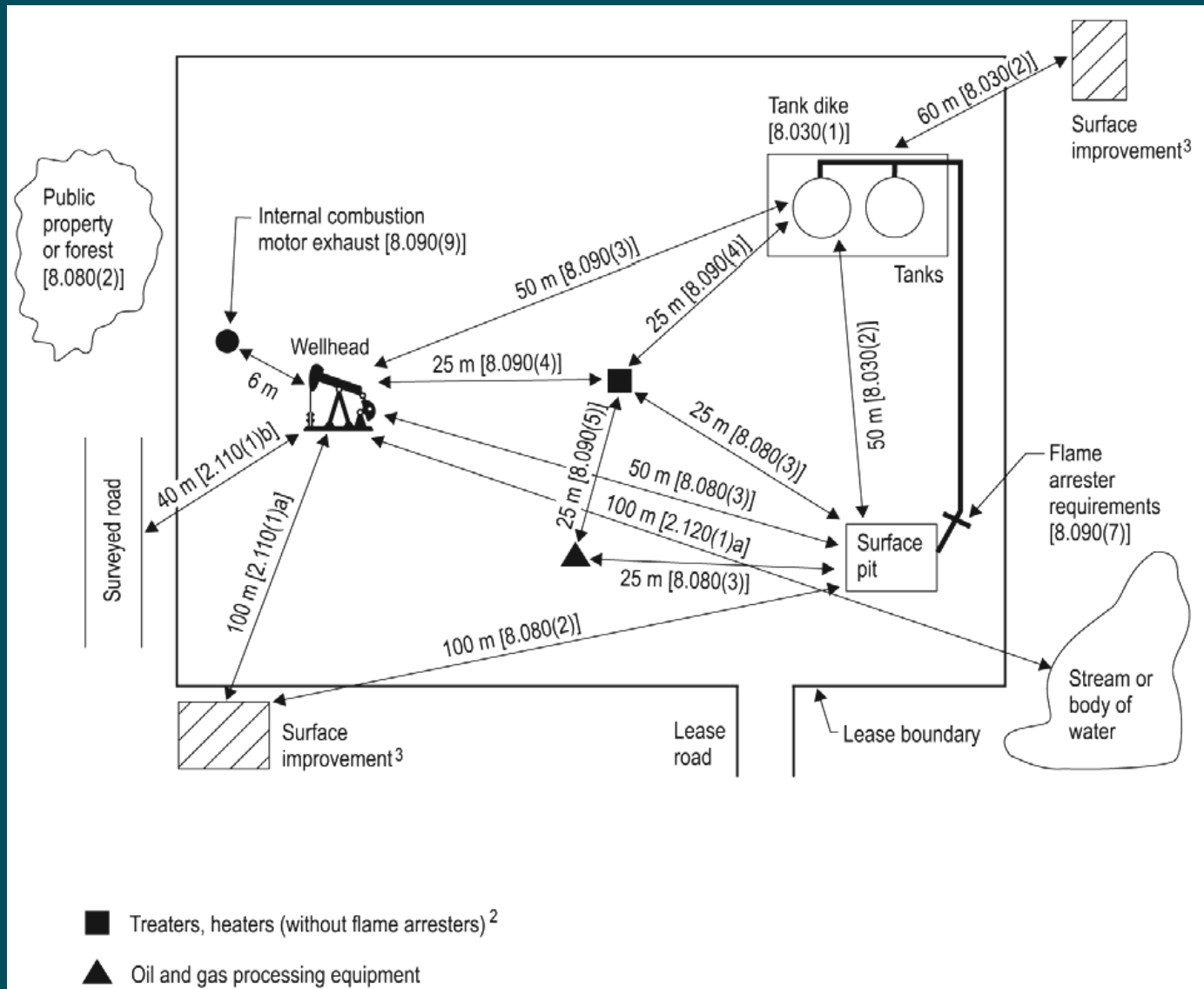
- Licensee must select the most appropriate method for determining the Sediments and Water (S&W) in accordance with *Directive 017*.
- There are two methods to obtain S&W: sampling or on-line analysis using a suitable instrument (water-cut analyzer or product analyzer).
- If a product analyzer (water cut analyzer) is used to determine water production, it must be calibrated annually.
- A tag or label must be attached to the product analyzer that identifies the analyzer serial number and date calibration.
- Sampling can be categorized by two methods: spot or grab sampling or continuous proportional sampling.

Section B, (1.3): Water/Other Measurement

- Where gas, air, water, or other substance is injected through a well to an underground formation, it shall be continuously measured by a method satisfactory to the Board.

Manual #	Result	Description
1.3.10.10	Low Risk	No measurement of injected/disposed water or other substance(s) [OGCR 14.200; Directive 017 (1.7.3(ii), (iv))]

Section B, (1.4): Spacing



Section B, (1.4): Spacing

Spacing requirements illustrated are as specified in the *Oil and Gas Conservation Regulations*.

- No person shall smoke within 25 m of a well, separator, oil storage tank or other unprotected source of ignitable vapour or on a rig or derrick at a well site.
- No flame type equipment shall be placed or operated within 25 metres of any process vessels unless, the flame type equipment is fitted with an adequate flame arrester.
- No flame type equipment shall be located in the same building as any process vessel or other source of ignitable vapour, unless
 - a) the air intakes and flues of all burners are located outside the building,
 - b) relief valves, safety heads, and other sources of ignitable vapours are vented outside the building and discharged above roof level, and
 - c) the building is adequately cross ventilated.

Section B, (1.5): Flaring, Incinerating, and Venting

Directive 060 & OGCR

If receive gas containing > 10 mol/kmol of H_2S or where the site maximum potential H_2S release rate is ≥ 0.04 m³/hour (heavy oil):

- The licensee of a well or the operator of a facility shall not discharge or permit to be discharged to the atmosphere stock tank vapours or any other gas produced from the well, unless they are burned.
- Operators must burn all nonconserved volumes of gas if volumes/flow rates are sufficient to support stable combustion.
 - ERCB may investigate vented volumes 500 m³/day (or lower), if it appears that stable combustion may be feasible.

Section B, (1.5): Flaring, Incinerating, and Venting

Gas Plant Flaring, Incinerating, and Venting Decision Tree

- Decision Tree analysis must be used to evaluate all new and existing gas plant flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m³ per month), such as pig trap depressuring.
- These evaluations must be updated annually or upon changes at the plant that materially change plant operation.

Section B, (1.5): Flaring, Incinerating, and Venting

- Operators must conserve solution gas at all sites where
 - a) combined flaring and venting volumes are $> 900 \text{ m}^3/\text{day}$ per site and the decision tree process and economic evaluation result in net present value of greater than $-\$50\,000$ Cdn
 - b) gas:oil ratio (GOR) is greater than $3000 \text{ m}^3/\text{m}^3$
 - c) flared volumes are greater than $900 \text{ m}^3/\text{day}$ per site and the flare is within 500 m of an existing residence, regardless of economics

Section B, (1.5): Flaring, Incinerating, and Venting

Clustering:

- Solution gas is economic to conserve in some areas if operators coordinate their efforts in an efficient, cooperative process.
- Operators of production facilities operating within 3 kilometres of each other or other appropriate oil and gas facilities (including pipelines) must jointly consider “clustering” when evaluating solution gas conservation economics.
- Operators of multiwell oil or bitumen developments must assess conservation on a project or development area basis regardless of distance. Evaluations must address all potential gas vent and flare sources associated with the multiwell development.

Section B, (1.5): Flaring, Incinerating, and Venting

Flare/Incinerator Stacks:

- Radiant heat intensity at ground level must not exceed 4.73 kW/m².
- If located within 5x the height of any buildings, height must be at least 2.5x the height of the highest building.
- For acid or sour gas (>10 mol/kmol H₂S), have min. height of 12 m.
- Must have sufficient height to provide adequate plume dispersion to comply with *Alberta Ambient Air Quality Objectives* for SO₂.
- Interconnecting lines must be secured to prevent whipping or flailing.
- Flare stacks for acid or sour gas (>10 mol/kmol H₂S) must have automated shutdowns (if facility not staffed 24 hours/day).

Section B, (1.5): Flaring, Incinerating, and Venting

Flare and incinerator separators/knock out drums must be

- provided in temporary (including well test) and permanent systems
- designed to remove droplets of 300-600 micron diameter and larger
- designed to have sufficient holding capacity
- if facility constructed after January 31, 2007, equipped with high-level alarms, in addition to liquid level indication
- if facility constructed prior to January 31, 2007, have visual level indicators, high-level facility shutdowns or high-level alarms, and operating procedures
- have high-level alarms & facility shutdowns if liquids are directed to vessel for storage or if liquids are contained in continuously combusted streams

Section B, (1.5): Flaring, Incinerating, and Venting

Non-routine flaring, incinerating, or venting operations:

- If flaring/venting operations will be <4 hours in duration and <30 10³m³:
 - No notification to ERCB or public required.
- Operators must investigate and correct causes of repeat nonroutine events.

Section B, (1.5): Flaring, Incinerating, and Venting

Cutback Requirements For Non-routine Flaring/Venting Events

- Table 1, *Directive 060*
- Partial equipment outages less than 5 days:
 - VRU repair, etc.
 - not required to cut back production as long as volumes flared or vented do not exceed $2 \times 10^3 \text{m}^3/\text{day}$

Section B, (1.5): Flaring, Incinerating, and Venting

Cutback Requirements For Non-routine Flaring/Venting Events

- Planned Shutdowns:
 - Less than 4 hours: Operators must reduce battery or solution gas plant inlet gas volumes by 50% of average daily solution gas production over the preceding 30-day period.
 - More than 4 hours: Operators must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period.
- If cutback can't be met, a variance may be given by ERCB Field Centre.

Section B, (1.5): Flaring, Incinerating, and Venting

Planned Shutdowns > 4 hours:

- Residents within 500 m must be notified at least 24 hours in advance.
- The local ERCB Field Centre must be notified at least 24 hours in advance.

Section B, (1.5): Flaring, Incinerating, and Venting

Cutback Requirements for Non-routine flaring or venting events

- Unplanned and emergency shutdowns:
 - Less than 4 hours: No reduction in inlet required.
 - More than 4 hours: Operators must reduce battery or solution gas plant inlet gas volumes by 75% of average daily solution gas production over the preceding 30-day period.
- If cutback can't be met, a variance may be given by ERCB Field Centre.

Section B, (1.5): Flaring, Incinerating, and Venting

Unplanned and emergency shutdowns > 4 hours:

- Residents within 500 m must be notified as soon as possible.
- The local ERCB Field Centre must be notified as soon as possible.

Section B, (1.5): Flaring, Incinerating, and Venting

Table 2. Temporary flaring, venting, and incinerating notification requirements^{1,2}

Type of operation (applies to sweet and sour streams)	Duration of event (hrs in 24-hr period)		Gas volume (10 ³ m ³ in a 24-hr period)	Notification ³
Temporary (i.e., for well cleanup, testing, or maintenance)	< 4	and	< 30	No notification ⁴
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains ≤ 10 mol/kmol H ₂ S	> 4	or	> 30	Residents, 1.5 km radius; EUB Field Centre
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains >10 mol/kmol H ₂ S	> 4	or	> 30	Residents, 3 km radius; EUB Field Centre
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	< 4		--	No public notification; ⁴ Notify EUB ⁵ if flaring >30 10 ³ m ³
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	> 4		--	Residents, 0.5 km radius; ⁵ EUB Field Centre

Section B, (1.5): Flaring, Incinerating, and Venting

- Smoke emissions from a well, battery, or gas plant must be controlled in accordance with *Oil and Gas Conservation Regulations* 7.040(1) and 9.050(6)(d), and *Directive 060* except under emergency circumstances due to equipment failure or as otherwise approved by the ERCB.
- Routine gas combustion must not result in continuous or repeat black smoke emissions.

Section B, (1.5): Flaring, Incinerating, and Venting

Flaring, Incinerating, and Venting Records (Logs)

- Operators must maintain a log of flaring, incinerating, and venting events and respond to public complaints.
- Logs must include
 - information on complaints
 - a description of each nonroutine flaring, incinerating, and venting incident and any changes implemented to prevent future nonroutine events of a similar nature from occurring
 - the date, time, duration, gas source or type (e.g., sour inlet gas, acid gas), and volumes for each incident
- Logs must be kept for a minimum of 12 months.

Section B, (1.5): Flaring, Incinerating, and Venting

Licensees must meet all other requirements outlined in *Directive 060* including:

- heating value and exit velocity for flares
- minimum residence time and exit temperature for incinerators
- flare/incinerator ignition system
- backflash control
- flare pits
- flaring, incinerating & venting logs

Section B, (1.6): Signs and Security

- The licensee of a well and the operator of a facility shall identify the well/facility by a conspicuous sign erected at the primary entrance to the well/facility that indicates
 - licensee/operator name
 - licensee/operator emergency phone number
 - surface location (LSD)
 - warning symbol:
 - Category I: Flammable (gas or liquid); Class 3; (if <10 ppm H₂S)
 - Category II: Poison Gas; Class 2. (if >10 ppm H₂S)
- If more than one well from one surface location, licensee must identify the bottom hole location of each well on a sign affixed to the wellhead.

ABC COMPANY

00/08-02-064-09-W5

Emergency Phone: 1-800-555-5555



Section B, (1.6): Signs and Security

- Fencing or alternative security measures (where required) must be in accordance with Sections 8.170 and 8.171 of the *Oil and Gas Conservation Regulations*.

Manual #	Result	Description
1.6.5.20	Low Risk	No or inadequate fence or alternative security measures where required. [OGCR 8.170, 8.171; Directive 057]

Section B, (1.6): Signs and Security

Oil and Gas Conservation Regulations

- Battery >10 mol/kmol H_2S , (or higher/lower as determined by ERCB):
 - if within 800 m of resident/public facility, 2 m high industrial fence around battery, and locked when unattended
 - if located elsewhere, a cattle type fence with a min. four strand barbed wire and either gate or cattle guard
- Wells with a pumping unit within 800 m of a town (or other centre), resident, campground, or other public facility:
 - ≥ 2 m high steel mesh fence with the mesh not greater than 130 cm^2 around the entire pumping unit, and equipped with a gate that is locked when unattended

Section B, (1.7): Emergency Controls and Relief System

Manual #	Result	Description
1.7.5.5	High Risk	Sour pressure relief valves in gas facility > 10 mol/kmol H ₂ S not tied into flare system [OGCR 7.060(1), (3)]
1.7.5.8	Low Risk	Operating gas catalytic heater with inoperable safety shut off. [OGCR 8.090(8); Alberta Regulation 62/2003 Occupational Health and Safety Regulation Part 1, 12(1)]
1.7.5.13	Low Risk	No or inadequate/inappropriate pop tank or alternate conditions not adhered to. [OGCR 8.031]

Section B, (1.8): Storage

- All storage requirements outlined in the *Oil and Gas Conservation Regulations* and *Directive 055: Storage Requirements for the Upstream Petroleum Industry* must be adhered to.

Manual #	Result	Description
1.8.5.5	High Risk	Contaminated materials or materials possessing the potential to leach stored directly on the ground. [OGCR 8.030(1); Directive 055 (3.5)]

Section B, (1.8): Storage

Single-Walled Aboveground Tanks $\geq 5 \text{ m}^3$:

- dike and liner required for facilities constructed after January 1, 1996
- dike capacity 110% of tank or 100% of largest & 10% of each additional tank
- spill control devices at fluid transfer points
- cathodic protection in corrosive environments
- tanks installed before January 1, 1996, do not require a liner but must be integrity-tested every 5 years

Section A, (1.8): Storage

Double-Walled Aboveground Tanks $\geq 5 \text{ m}^3$:

- Primary tank required to be separated from the secondary containment system so as to provide continuous interstitial space
- equipped with a method of overfill protection or an automatic shutoff mechanism to prevent overflow of primary tank
- spill control devices at fluid/delivery connection
- system to monitor interstitial space on a monthly frequency
- be protected against damage from vehicular traffic
- be equipped with a valve as close as practical to the tank to prevent draining should a piping break/leak occur

Section B, (1.8): Storage

Underground Storage Tanks (UST):

- Tanks installed after January 1, 2002, must be double-walled and require monthly monitoring for leak detection.
- Newly Installed USTs and associated piping must be tested for integrity as a complete system prior to placing in service.
- Steel tanks must have cathodic protection and external coating.
- Spill control devices at hose connections and fluid transfer points.
- Single-walled tanks installed prior to January 1, 2002, must be integrity-tested every 3 years.

Section B, (1.8): Storage

Containers:

- Portable devices with an internal volume less than 1 m³:
 - Total combined volume of containers on site without secondary containment cannot exceed 1 m³.
 - Container and stored material must be compatible.
 - Impervious dike, curb and/or collection tray capacity must be 100% of the largest container or 10% of the aggregate volume, whichever is greater.
 - Monthly visual inspection.

Section B, (1.8): Storage

- Licensees must meet all other requirements outlined in *Directive 055* including:
 - temporary storage
 - storage duration
 - bulk pads
 - lined earthen excavations
 - inspection, monitoring, and record keeping requirements

Section B, (2.1): ERPs

Licensees are responsible to ensure that they are fully prepared and capable of responding to any level of emergency.

- Emergency preparedness and response includes activities done prior to an emergency so that personnel are ready and able to respond quickly/appropriately, as well as activities that take place during the incident.
- This includes activities such as
 - identifying hazards,
 - preparing and maintaining Emergency Response Plans (ERPs),
 - ensuring that the ERPs identify sufficient resources and equipment for use during an emergency, and
 - designating response personnel and ensuring that they can carry out their duties through training, drills, and exercises.

Section B, (2.1): ERPs

Oil and Gas Conservation Regulations:

- **8.002(1)** *A licensee of a well or facility shall prepare a corporate ERP in accordance with Directive 71, Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry, and any amendments to Directive 71, as published by the Board.*

Section A, (2.1): ERPs

- Site-specific ERPs are not required for every drilling, production, or pipeline operation in the province.
- When a site-specific ERP is not required, a corporate-level ERP is used by the licensee to handle emergency events.
- The licensee must have a corporate-level ERP with preplanned procedures that will aid in effective response to an emergency.
- The licensee must ensure that a call to its 24-hour emergency telephone number initiates immediate action.

Manual #	Result	Description
2.1.5.25	High Risk	Failure to ensure that a call to the licensee 24-hour emergency telephone number initiates immediate action. [Directive 071 (2.1(3))]

Section B, (2.1): ERPs

- The licensee must submit a sour well site-specific drilling and/or completion ERP to the ERCB for approval for the following, or for any other situation in which the ERCB determines that a plan is required:

Well Type	Operation	Surface development within the EPZ	No Surface development within the EPZ
Critical sour	Drilling and/or completion	Yes	Yes
Noncritical sour		Yes	No

Critical Sour- A well with an H₂S release rate greater than 2.0 m³/second or wells with lower rates in close proximity to an urban centre as defined in *ID 97-6: Sour Well Licensing and Drilling Requirements*.

Section B, (2.1): ERPs

- Licensees must have an approved sour operations ERP for the following, or for any other situation in which the ERCB determines:

Operation	Surface development within the EPZ	No surface development within the EPZ
Sour pipeline operation	Yes	No
Producing, shut-in, or injecting noncritical sour well	Yes	No
Producing, shut-in, or injecting critical sour well	Yes	Yes
Sour facility operation	Yes	No

- The licensee must ensure that the ERP is approved by the ERCB before commencement of operations.

Section B, (2.1): ERPs

- As soon as a required ERP has been approved by the ERCB, the licensee must
 - distribute copies to the government agencies listed in Appendix 5 of *Directive 071* within 10 business days after approval, unless the agency requests otherwise in writing
 - provide a copy of the ERP, excluding confidential resident and personal information, to any resident within the EPZ who requests in writing to have a copy
 - ensure that all required plan holders have a copy of the approved ERP

Section B, (2.1): ERP's

- Licensee must conduct a public awareness program every second year with residents within the EPZ through consultative processes. The licensee is expected to:
 - provide key emergency response information,
 - review public protection measures, and
 - answer any concerns or questions that residents may have.
- Regardless of whether residents wish to meet with the licensee, the licensee is expected to provide an updated public information package to each residence.

Section B, (2.1): ERPs

- Licensee is responsible for ensuring that ERPs are maintained regularly and that updates are sent to the ERCB and other plan holders (where required).
- The ERCB no longer requires the submission of annual ERP updates for approval, but continually checks ERP accuracy. ERPs that are not current and therefore could result in ineffective emergency response will be subject to enforcement action by the ERCB.

Manual #	Result	Description
2.1.5.13	High Risk	Failure to have an up-to-date copy of the ERP at response location(s) in area of operations. [Directive 071 (11.1(1), (14.1(1)); Bulletin 2008-15 (2.2)]
2.1.10.3	High Risk	Failure to demonstrate that the plan management system ensures that the ERPs are up-to-date as changes are identified. [Directive 071 (14.6(22)); Bulletin 2008-15 (2.2)]

Section B, (2.1): ERPs

Exercise Requirements:

- The licensee must test its ERPs through the following:
 - tabletop exercise, held annually for each area ERP, except if a major exercise is held, and
 - major exercise, held once every three years for each area ERP.
- If have multiple area ERPs with same response personnel and infrastructure, the ERPs may be tested through one exercise.
- The licensee must
 - notify the appropriate ERCB Field Centre 30 days in advance of a scheduled exercise via the ERCB Digital Data Submission (DDS) system, and
 - invite the local authority, Regional Health Authority, or any other government department or agency to participate and/or observe at major exercises.

Section A, (3.1): Emissions

- Must meet requirements outlined in:
 - *Oil and Gas Conservation Regulations*
 - *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*
 - *Directive 038: Noise Control*
 - *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators*
 - *ERCB Bulletin 2009-44*
 - *CAPP Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities*
 - *CAPP BMP Control of Benzene Emissions from Glycol Dehydrators*

Section B, (3.1): Emissions

Directive 060

- Limitations of Venting Gas Containing H₂S or Other Odorous Compounds:
 - 1) Gas containing more than 10 mol/kmol H₂S must not be vented to the atmosphere. This includes gas off stock tanks, PSVs, and equipment blowdown systems.
 - 2) Venting must not result in H₂S odours outside the lease boundary.
 - a) The ERCB recommends any PSVs or blowdown systems be connected to a flare system where such systems are installed.
 - 3) Venting must not result in off-site exceedances of the *Alberta Ambient Air Quality Objectives*.

Section B, (3.1): Emissions

Directive 060

- Operators must demonstrate that SO₂ and H₂S emissions will not result in exceedance of *Alberta Ambient Air Quality Objectives* if the gas contains more than or equal to
 - 10 mol/kmol H₂S, and/or
 - one tonne per day of sulphur.
- Operators combusting gas below this are encouraged to consider dispersion modeling.
- Facilities requiring approval from Alberta Environment may require more detailed evaluation.

Section B, (3.1): Emissions

Directive 060

- Operators must evaluate impacts of sour gas flaring/incinerating on ambient air quality if it is proposed to burn sour gas greater than 10 mol/kmol H₂S or 1 tonne per day of sulphur.
- Operators must evaluate cumulative effects on ambient air quality if there are continuous SO₂ emissions sources within 7 km or within the isopleth of one-third of the *Alberta Ambient Air Quality Objective* for SO₂, whichever distance is less.

Section B, (3.1): Emissions

Directive 060

- Noncombustible gas mixtures containing odorous compounds including H₂S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odorous compounds.

Section B, (3.1): Emissions

Directive 039

- Operators must assess and control benzene emissions so that cumulative emissions from all sources do not exceed limits.

Date facility or lease site commissioned	Benzene emission limits
Prior to January 1, 1999	
- > 750 m to permanent resident or public facility	5 tonnes/yr
- < 750 m to permanent resident or public facility	3 tonnes/yr
January 1, 1999, to January 1, 2007	3 tonnes/yr
After January 1, 2007	1 tonnes/yr

Section B, (3.1): Emissions

Directive 039

- Operators must complete and post a Dehydrator Engineering and Operations Sheet (DEOS).
 - must be updated every 12 months
- Shut in dehy's do need a DEOS.
- Decommissioned dehy's (is not and can not be easily connected and put in service) do not need a DEOS.
- Dehy's out of service for 12 months or more would be considered new or relocated when brought back on line (meet 1 tonne/yr).

Section B, (3.1): Emissions

Directive 038

- New facilities must meet a Permissible Sound Level (PSL) of 40 dBA Leq (night time) at 1.5 km from the facility fence line if there are no closer dwellings.
- Licensees must in a timely manner make every reasonable attempt to resolve any noise-related complaint through direct contact with the complainant.

Manual #	Result	Description
3.1.5.20	High Risk	Failure to meet the permissible sound level at the nearest or most impacted dwelling. [Directive 038 (2.1(3)), (2.2(9)), (3.1(3)), (4.4(22)), (5.1(1)), Appendix 1]
3.1.10.5	Low Risk	Noise complaint response/procedures not conducted in accordance with requirements. [Directive 038 (4)]

Section B, (3.2): Waste Management

- The licensee of a well or pipeline and the operator of a facility shall maintain the well, pipeline or facility in a clean condition and shall ensure that oilfield wastes do not create or constitute a safety hazard or nuisance or adversely affect air, soil, surface water or groundwater.
- Licensees must meet the requirements outlined in:
 - *Oil and Gas Conservation Regulations*
 - *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*
 - *Informational Letter IL 99-02*
 - *Interim Directive ID 99-04*
 - *Interim Directive ID 2000-03*

Section B, (3.2): Waste Management

- Licensees generating oilfield waste shall
 - (a) properly characterize and classify oilfield wastes
 - (b) use appropriate oilfield waste storage, treatment and disposal
 - (c) understand the capabilities and limitations of the methods selected for the treatment and disposal
 - (d) complete and maintain accurate documentation/records
 - (e) disclose to waste carriers and receivers the characteristics and classification of the oilfield wastes
 - (f) ensure waste operational requirements are satisfied and, if applicable, approvals are in place for on-site oilfield waste handling, treatment, and disposal methods

Section B, (3.2): Waste Management

- Oilfield wastes that can be separated from production stream can be harmful to downstream oil handlers.
- Oilfield wastes banned from direct injection into any pipeline system:
 - all non-hydrocarbon based wastes
 - all solid wastes
 - non-hydrocarbon based drilling fluid
 - all fracturing sands
 - all radioactive wastes
 - halogenated solvents and halogenated organic chemicals
 - water based wastes including produces water, acid water, process water, hydrotest fluids, etc.
 - all chemical wastes including sludges, whether unused, spent or contaminated

Section B, (3.3): Spills

- When oil, water, or unrefined product is spilled or released the licensee shall immediately take steps to contain and clean up the spill or release.
- If reportable, the licensee or operator shall immediately orally report the size and location of the spill to the appropriate field centre of the Board.

Manual #	Result	Description
3.3.5.5	High Risk	Facility closer than 100 metres to the normal high water mark of a body of water or permanent stream without appropriate protective measures. [OGCR 8.060]
3.3.5.10	High Risk	Spill or release not contained/cleaned up. [OGCR 8.050(1), 8.051(b)]
3.3.10.5	High Risk	No notification of a reportable spill or release to the ERCB. [OGCR 8.050(2), 8.051(a), 12.140; Informational Letter (IL) 98-01 (4.1)]
3.3.10.10	Low Risk	Late notification of a reportable spill or release to the ERCB. [OGCR 8.050(2), 8.051(a), 12.140; Informational Letter (IL) 98-01 (4.1)]

Section B, (3.3): Spills

Licensee must “orally report” to the ERCB “at the first available opportunity” for

- any release more than 2 m³ on lease
- any release off lease
- any release or break from a pipeline
- pipeline hits
- uncontrolled gas release > 30 e³m³
- any release that may cause, is causing or has caused an adverse effect
- any well flowing uncontrolled
- any fire where loss exceeds 2 m³ of oil, or 30 000m³ of gas or where damage to well head occurs
- any burning of effluent from a well or facility

Section B, (3.4): Surface Water

Collected waters must be tested and meet the following criteria prior to being released in a controlled fashion to adjacent lands:

- chloride content 500 mg/L maximum
- pH 6.0 to 9.0
- no visible hydrocarbon sheen
- no other chemical contamination
- landowner or occupant consent
- water not allowed to flow directly into any watercourse
- each release recorded, including prerelease test data and estimated volume of water released

Manual #	Result	Description
3.4.5.5	High Risk	Release criteria of collected surface water not met prior to release to adjacent lands. [OGCR 9.050(8)(b); Directive 055 (11)]

Section B, (4.1): Abandonment

- ERCB requires accurate information on the operational status of wells, facilities, and pipelines.
- A licence status change notification must be submitted electronically through the ERCB's Digital Data Submission (DDS) system.
- A licensee must notify the ERCB within 30 days of the completion of the abandonment of a licensed well or facility.

Manual #	Result	Description
4.2.10.5	Low Risk	No notification of facility abandonment. [Directive 006 Appendix 3(1)]

Section B, (99): Other

Other ERCB Risk Assessed Noncompliance's can be found on the ERCB website (www.ercb.ca); Industry Zone; Compliance and Enforcement; Risk Assessed Noncompliance.

Manual #	Result	Description
99.5.5	Low Risk	Noncompliant with other low risk ERCB requirement(s) (see comments for details). [Refer to the applicable ERCB requirement (must be a risk-assessed noncompliance).]
99.10.10	High Risk	Noncompliant with other high risk ERCB requirement(s) (see comments for details). [Refer to the applicable ERCB requirement (must be a risk-assessed noncompliance).]

If you have questions/comments,
please contact your local ERCB field
centre or email the ERCB industry
education coordinator
industry.education@ercb.ca