

Directive 060

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Upstream Petroleum Industry Flaring, Incinerating, and Venting

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1 Introduction

1.1 Purpose of This Directive

The Alberta Energy Regulator (AER) *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* contains the requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities. *Directive 060* requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters) licensed by the AER in accordance with the *Pipeline Act*. With the exception of oil sands mining schemes and operations, *Directive 060* applies to all schemes and operations approved under section 10 of the *Oil Sands Conservation Act (OSCA)*. *Directive 060* does not apply to any processing plants approved under section 11 of the *OSCA*.

Most of these requirements have been developed in consultation with the Clean Air Strategic Alliance (CASA) to eliminate or reduce the potential and observed impacts of these activities and to ensure that public safety concerns and environmental impacts are addressed before beginning to flare, incinerate, or vent. *Directive 060* requirements are also aligned to ensure compliance with Alberta Environment and Parks (AEP) *Alberta Ambient Air Quality Objectives and Guidelines (AAAQO)*.

Note: Appendices have been included to further the understanding of *Directive 060* requirements. See appendix 1 for a list of references and contacts, appendix 2 for definitions of terms, and appendix 3 for abbreviations.

1.2 What's New in This Edition

Interim Directive 2003-01 was replaced by *Directive 087*. References have been updated. References to *IL 98-01* have been removed as the information letter has been rescinded. Explicit conditions have been added to table 1 to indicate when the AER field centre must be notified of an event.

1.3 Flaring, Incineration, and Venting Management Hierarchy and Framework

Flaring, incinerating, and venting are associated with a wide range of energy development activities and operations, including disposal of gas associated with

- oil, bitumen, and gas well drilling;
- oil, bitumen, and gas well completion or well servicing (well “cleanup”);
- gas well testing to estimate reserves and determine productivity;
- routine oil or bitumen production (solution gas);
- planned nonroutine depressurizing of processing equipment and gas pipelines for maintenance;

- unplanned nonroutine depressurizing of process equipment and gas pipelines due to process upsets or emergency; and
- oilfield waste management facilities.

Two multistakeholder teams from CASA have made recommendations for flaring, incineration, and venting for the upstream petroleum industry, and the AER has based this directive on those recommendations (see appendix 4 for background on *Directive 060*).

In particular, the AER has adopted CASA's objective hierarchy and its framework for managing routine solution gas flares (see figure 1; www.casahome.org) and has extended its application of the hierarchy to include flaring, incineration, and venting of gas in general.¹

In accordance with the objective hierarchy, licensees, operators, and approval holders must evaluate the following three options:

- Can flaring, incineration, and venting be eliminated?
- Can flaring, incineration, and venting be reduced?
- Will flaring, incineration, and venting meet performance standards?

¹ See CASA's website www.casahome.org.

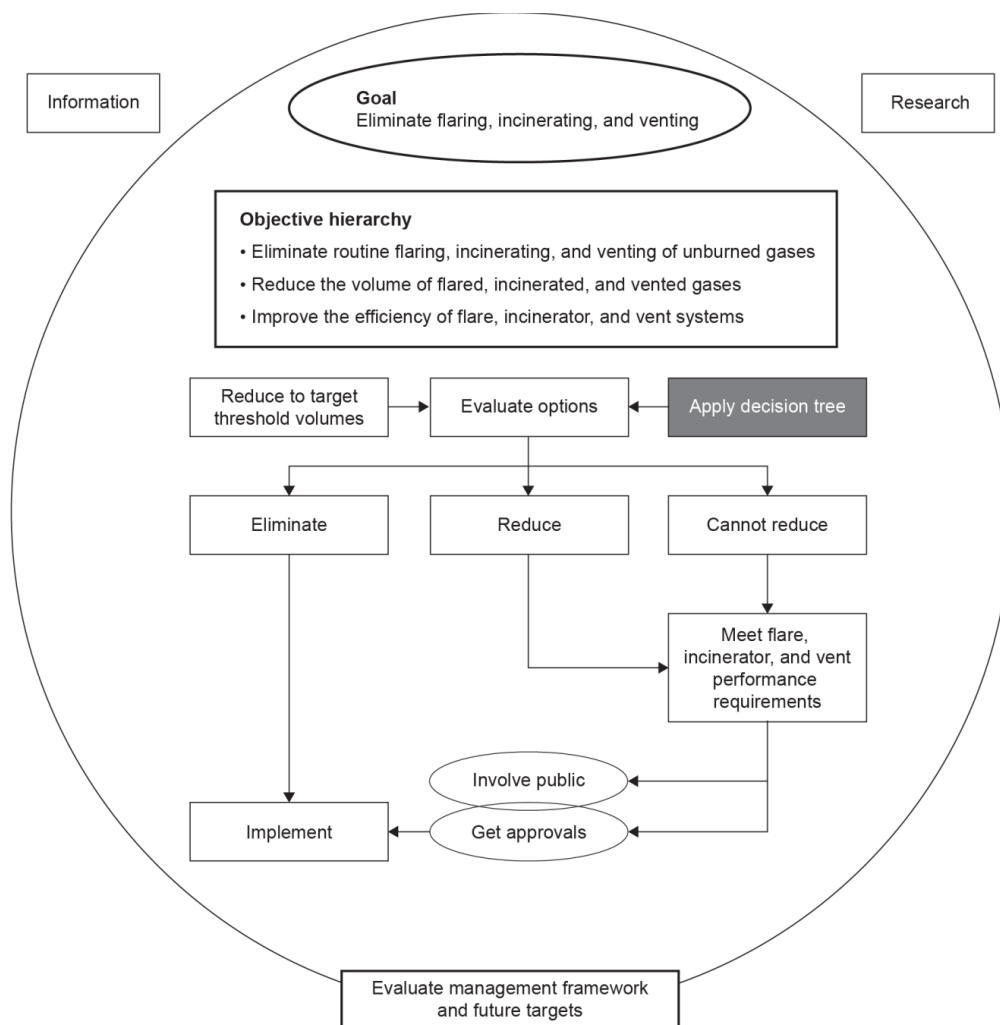


Figure 1. Solution gas flaring/venting management framework (adapted from CASA)

1.4 Access to Production Flaring, Incineration, and Venting Data

The AER reports flaring, incineration, and venting volumes annually in the *ST60B: Upstream Petroleum Industry* flaring report on the AER website www.aer.ca.

The AER also makes flaring, incineration, and venting information available to licensees, operators, and approval holders in order to facilitate solution gas conservation and clustering opportunities, as described in section 2.13.

1.5 AER Requirements

Following AER requirements is mandatory for the responsible duty holder, as specified in legislation (e.g., licensee, operator, company, applicant, approval holder, or permit holder). The term “must” indicates a requirement, while terms such as “recommends” and “expects” indicate a recommended practice.

Each AER requirement is numbered.

Information on compliance and enforcement can be found on the AER website.

1.6 Frequency

For the purposes of this directive, terms like annually or quarterly are defined as follows:

- Monthly is at least once per calendar month.
- Bimonthly is at least once every two consecutive calendar months.
- Quarterly means at least once per calendar quarter. Calendar quarters are January to March, April to June, July to September, and October to December.
- Triannually means at least once per four calendar months.
- Annually means at least once every four calendar quarters.

Example: If a survey needs to be done annually and the last survey occurred in May 2019 (second quarter), the operator has to perform another survey by the end of the second quarter of 2020 (June 30).

1.7 Notification Through the Designated Information Submission System

The licensee, operator, or approval holder must notify the appropriate AER field centre before planned flaring, venting, or incineration operations by completing and submitting an AER flaring/incineration/venting notice form within the designated information submission system. The AER strongly encourages all licensees, operators, and approval holders to follow the FIS Web User Guide when completing and submitting this form. Any operations that may result in a public complaint must be called in to the appropriate AER field centre's 24-hour emergency phone number (see appendix 1).

For questions on using FIS, contact the FIS administrator by email at FIS.Administrator@aer.ca or by telephone at 403-297-4845.

1.8 Review and Revision

The AER will review the methane emission requirements in this directive no later than December 31, 2022, taking into account

- the efficiency and effectiveness of the requirements in reducing methane emissions to meet the outcome of a 45 per cent decrease by 2025 relative to 2014 levels; and
- developments in practices, processes, and technologies to control methane emissions.

Based on the outcome of the review, requirements may be revised.

2 Solution Gas Management (Crude Oil / Bitumen Battery Flaring, Incineration, and Venting)

The AER's goal is to have the upstream petroleum industry continue to reduce the volume of solution gas routinely flared, incinerated, and vented. The AER expects that the upstream petroleum industry will pursue continuous improvement in reducing solution gas flaring, incineration, and venting in Alberta, and, in consultation with stakeholders, will monitor progress to determine the need for additional requirements to facilitate increased solution gas conservation.

Combustion of solution gas in incinerators is not considered an alternative to conservation.

For solution gas management and disposition reporting, incinerated gas must be reported as flared.

Conservation is defined as the recovery of solution gas for use as fuel for production facilities, for other useful purposes (e.g., power generation), for sale, or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery). Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in section 2.9.

In this section, for the “combined flared and vented volumes” the vented volumes must not exceed the vent gas limits in section 8.

2.1 Solution Gas Flaring Reduction Targets

Directive 060 incorporates recommendations made by CASA in 2002, 2004, and 2005 to reduce flaring.

- 1) The Alberta solution gas flaring limit is 670 million cubic metres (10^6 m^3) per year (50 per cent of the revised 1996 baseline of $1340 \times 10^6 \text{ m}^3/\text{year}$).
- 2) If solution gas flaring exceeds the $670 \times 10^6 \text{ m}^3$ limit in any year, the AER will impose reductions that will stipulate maximum solution gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than $670 \times 10^6 \text{ m}^3/\text{year}$. For example, solution gas flaring could be limited to a maximum of 500 thousand (10^3) m^3/year at any one site.

2.2 Solution Gas Venting Reduction

The AER does not consider venting an acceptable alternative to flaring. If venting is the only feasible alternative, the requirements in section 8 must be met.

In 2005, 59 per cent less solution gas was vented than in 2000. The CASA Flaring and Venting Project Team considered solution gas venting in the report, *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project*

Team, which it released in 2004.² The AER accepts these recommendations and has incorporated them into *Directive 060*.

2.3 Solution Gas Flaring and Venting Decision Tree

The AER adopted the solution gas flaring/venting management framework (figure 1) and endorses the solution gas flaring and venting decision tree process (figure 2) as recommended by CASA. The licensee or operator must apply this decision tree to combined flaring and venting of more than 900 m³/day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.

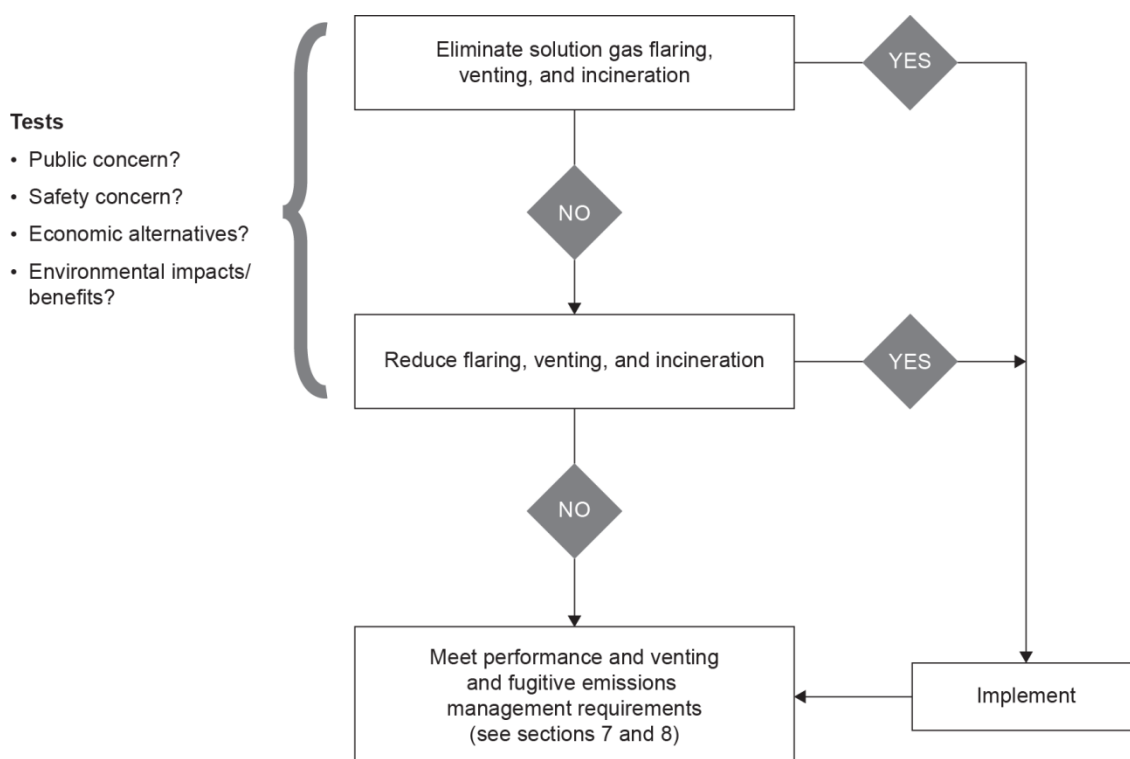


Figure 2. Solution gas flaring/venting decision tree (adapted from CASA)

2.4 Conservation at Crude Bitumen Batteries

For the purpose of *Directive 060*, crude bitumen battery is defined in appendix 2.

- 1) The licensee or operator of a multiwell bitumen site must build solution gas conservation lines to one common point on the lease as part of initial construction.
- 2) For new bitumen wells, the test period (excluding completion and cleanup operations) limit is either six months or until combined flared and vented volumes at the site exceed a rolling average of 900 m³/day for any consecutive three-month period, whichever is less.

² This and other reports from this team are available on CASA's website, www.casahome.org.

- a) As soon as testing shows that combined flaring and venting volumes at the site exceed 900 m³/day, conservation must be evaluated as described in section 2.9. Volumes are calculated based on a three-month rolling average.
 - b) If conservation is required, it must occur as quickly as possible and must not extend for more than six months after flow-rate determination. Shorter tie-in times must be pursued wherever possible. Wells must be shut in if the required conservation is not operational within the timelines noted above.
- 3) If testing shows that combined flaring and venting volumes at the site do not exceed 900 m³/day, economic evaluation of solution gas conservation is not required and the well may proceed to produce without conserving the solution gas. The AER, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m³/day.
 - 4) The vent gas volumes from testing must not exceed the vent gas limits specified in section 8.

2.5 Conservation at Conventional Crude Oil Batteries

For the purpose of *Directive 060*, crude oil battery is defined in appendix 2.

In general, for new oil wells the solution gas flaring during the test period must not extend beyond the time required to obtain data for the economic evaluation and for sizing conservation equipment. Any flaring for testing, cleanup, and completions must not exceed 72 hours (see section 3.2 for further details and extensions to time limits).

- 1) Upon completion of the testing period, if testing shows that combined flaring and venting volumes at the site will exceed 900 m³/day, solution gas conservation must be evaluated as described in section 2.9. The wells must be shut in at the end of the test period and remain shut in pending the results of the solution gas conservation evaluation process.
 - a) If the results of the solution gas conservation evaluation indicate that conservation is required, the wells must remain shut in until conservation is implemented.
 - b) If the results of the solution gas conservation evaluation indicate that conservation is not required and the AER has not directed that conservation be implemented, the wells may proceed to produce without conserving the solution gas.
- 2) If testing shows that combined flaring and venting volumes at the site do not exceed 900 m³/day and the AER has not directed that conservation be implemented, the wells may proceed to produce without conserving the solution gas. The AER, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m³/day.
- 3) The vent gas volumes from testing must not exceed the vent gas limits specified in section 8.

2.6 General Conservation Requirements at all Condensate Producing Sites and Crude Oil and Crude Bitumen Batteries

These requirements apply to all condensate producing sites and crude oil and crude bitumen batteries unless otherwise specified.

- 1) The licensee or operator must conserve gas at all sites³ where
 - a) the combined volume of flare gas and vent gas is greater than 900 m³/day per site and the decision-tree process and economic evaluation (see section 2.9) result in a net present value (NPV) greater than –Cdn\$55 000;
 - b) the gas-oil ratio (GOR) is greater than 3000 m³/m³. All wells producing with a GOR greater than 3000 m³/m³ at any time during the life of the well must be shut in until the gas is conserved;
 - c) the AER directs the licensee, operator, or approval holder to conserve flare gas and vent gas, regardless of economics.
- 2) Conserving facilities within 500 m of a residence with first gas disposition before January 1, 2020, must continue conservation if gas production volumes are greater than 900 m³/day, regardless of economics. After January 1 2020, where unconserved gas volumes greater than 900 m³/day are combusted within 500 m of a residence, licensees or operators must use an incinerator (a flare is not permitted within 500 m of a residence).
- 3) For any site that has with a combined volume of flare gas and vent gas greater than 900 m³/day and is not conserving, an economic evaluation must be completed every 12 months using the criteria in section 2.9.
- 4) On a case-by-case basis, the AER may still require an economic evaluation for any site that is not conserving and has a combined volume of flare gas and vent gas less than 900 m³/day if we believe that conservation may be feasible.
- 5) Conserving facilities must be designed for 95 per cent conservation with a minimum operating level of 90 per cent.
- 6) The licensee or operator may apply to discontinue conservation if annual operating expenses exceed annual revenue. See section 2.6(7).
- 7) The licensee or operator must get approval from the AER to discontinue conservation once it has been implemented at any facility, and must
 - a) complete a decision tree to evaluate alternatives to discontinuing conservation,
 - b) provide information on actual annual operating expenses and revenues,

³ A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.

- c) notify the appropriate AER field centre and residents within 500 m of its intention to discontinue conservation and initiate flaring or venting at a site, and
- d) if conservation facilities are not operational, comply with table 1 until such time as approval from the AER to discontinue conservation is granted.

2.7 Clustering

Clustering is defined as the practice of gathering the solution gas from several flares or vents at a common point for conservation. Solution gas is economic to conserve in some areas if licensees and operators coordinate their efforts in an efficient, cooperative process to take advantage of combined gas volumes and economies of scale. Furthermore, solution gas conservation economics (see section 2.9) will be enhanced if conservation is incorporated into the initial planning of larger multiwell projects.

- 1) Licensees or operators of active production facilities operating within three kilometres (km) of each other or other appropriate oil and gas facilities (including pipelines) must evaluate clustering when evaluating solution gas conservation economics.

The AER may suspend production in the area under consideration until the economic assessment is complete.

The AER recommends that

- all licensees and operators exchange production data and jointly consider clustering of solution gas production or regional gas conservation systems, and
 - the licensee or operator with the largest flare and vent volumes take the lead in coordinating the evaluation of conservation economics for the area.
- 2) The licensee or operator of a multiwell oil or bitumen development 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.
 - a) The licensee or operator must incorporate provision for conservation at all stages of project development to optimize the opportunity for economic conservation of solution gas.
 - b) Applications under *Directive 056: Energy Development Applications and Schedules* for multiwell oil or bitumen developments must include a summary of the gas conservation evaluation and a description of the licensee or operator's related project plans.

The AER may suspend production at any facility until the economic assessment is complete.

2.8 Power Generation Using Otherwise-Flared/Vented Gas

Power generation is a means of conserving solution gas. The operator or licensee should consider power generation if distribution lines are nearby or if on-site power is required. The AER may investigate flared and vented volumes as low as 500 m³/day if it appears that gas is stable.

- 1) Approval of electrical power plants by the Alberta Utilities Commission is required under the *Hydro and Electric Energy Act*.

Alberta Utilities Commission Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations provides application requirements for power plant applications and includes a simplified application form for electric power generating projects of 1.0 megawatt (MW) or smaller.

- 2) Power plants with a generation capacity greater than 1.0 MW at peak load require approval issued by AEP under the *Environmental Protection and Enhancement Act (EPEA)*.

2.9 Economic Evaluation of Gas Conservation

If conservation is determined to be economic by any method using the economic decision tree process, the gas must be conserved.

- 1) Methods of conservation must include pipeline to sales, fuel, power generation, pressure maintenance, or any other method that may become available.
- 2) Licensees or operators must update the conservation economics for any sites that are flaring or venting combined volumes of more than 900 m³/day and that are not conserving every 12 months. This information, with the responsible individual named and the document dated, is to be kept on file by the licensee or operator and must be provided to the AER upon request. Evaluation information may be stored at a central location rather than on site.
- 3) A licensee or operator must provide the evaluation to the AER within five working days of receipt of a request.
- 4) A licensee must complete the economical evaluation process in accordance with *Directive 060* requirements.

2.9.1 Economic Evaluation Criteria

Economic evaluations of gas conservation must use the criteria listed below. The licensee or operator must consider the most economically feasible option in providing detailed economics. Specific AER economic evaluation submission requirements are listed in section 2.9.2.

- 1) Evaluations must be completed on a before-tax basis and must exclude contingency and overhead costs.
- 2) Conservation economics must be evaluated on a royalties-in basis (paying royalties) for incremental gas and gas by-products that would otherwise be flared or vented. If the economic

evaluation results in an NPV less than –Cdn\$55 000, the licensee or operator must re-evaluate the gas conservation project on a royalties-out basis (not paying royalties). If the evaluation results in an NPV –Cdn\$55 000 or more, the licensee or operator must proceed with the conservation project and may then apply to Alberta Energy for an “otherwise flared solution gas” royalty waiver.

- 3) Price forecasts used in the evaluation of solution gas conservation projects (gas gathered, processed, and sold to market) must use the most recent version of commodity price forecast from GLJ Petroleum Consultants Limited. Gas prices must be obtained from the “Natural Gas and Sulphur Price Forecast Table” in the “ARP” column (\$Cdn/MMBtu). Condensate prices must be obtained from the “Crude Oil and Natural Gas Liquids Table” in the “Alberta Natural Gas Liquids Section – Edmonton Pentanes Plus” column (\$Cdn/bbl).
- 4) Price forecasts for power generation projects must reflect the most recent 12-month rolling average of the pool monthly summary price as published by the Alberta Electric System Operator (AESO).⁴ The power price must be escalated at the long-term inflation rate (see item 9). Alternatively, the cost of the power displaced at the site may be used.
- 5) The licensee or operator must have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes). The production forecast must be reviewed by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.⁵
- 6) The licensee or operator must have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs must be approved-for-expenditure quality numbers based on selection of appropriate technology. Any capital costs incurred before the initiation of the solution gas project (i.e., sunk costs) must not be included in the analysis; only future capital costs related to solution gas conservation may be included.
 - a) For new flares, if capital cost savings result from implementing gas conservation, such as any equipment that would otherwise be required, the flares must be considered in the conservation economic evaluation and subtracted from the overall cost of the conservation infrastructure in evaluating the economics of solution gas tie-in.
 - b) Salvage value of gas conservation infrastructure must be included as project revenue in the year the value would be realized (e.g., transfer of a gas compressor from one conservation project at the end of that project’s life to another conservation project). The salvage value must be a reasonable market value estimate of the equipment and not a depreciated value from a taxation perspective.

⁴ The most recent 12-month rolling average of the pool monthly summary price can be found on the AESO website at <http://ets.aeso.ca>.

⁵ *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

- 7) The incremental annual operating costs for the gas conservation project, including gas gathering and processing fees, are to be assumed as up to 10 per cent of the initial capital cost of installing the conservation facilities. If the gas contains 10 moles per kilomole (mol/kmol) hydrogen sulphide (H₂S) or more, the incremental annual operating costs for the solution gas project may be assumed to be up to 20 per cent of the capital cost to initially install the conservation facilities.
 - a) The economic evaluation must account for any cost savings, such as reduced costs for trucking or equipment rental and reduced carbon levies.
- 8) The incremental annual operating costs for power generation projects are to be assumed as up to 10 per cent of the initial capital cost of installing the generation facilities. Standby fees may be calculated in addition to this 10 per cent allowance.
- 9) The most recent inflation rate must be based on the current economic trends report published quarterly on the Government of Alberta, Treasury Board and Finance, Economy and Statistics website.
- 10) The discount rate must be equal to the prime lending rate of ATB Financial on loans payable in Canadian dollars plus 3 per cent, based on the month preceding the month the evaluation was conducted in. This rate is reviewed periodically by the AER and will be revised if the cost of capital for the oil and gas industry changes significantly.
- 11) A solution gas conservation project is considered economic, and the gas must be conserved, if the economics of gas conservation generates an NPV before-tax of more than –Cdn\$55 000.
 - a) The NPV is defined as the sum of discounted, annual, before-tax cash flows for the economic life of the solution gas conservation project, where each annual before-tax cash flow is net of that year's conserving project capital investment, if any.
 - b) The economic life of a conservation project is defined as the period from the start of the project to the time when annual expenses exceed annual revenue. Note that section 2.6(6) provides a process whereby the licensee or operator may apply to discontinue conservation if annual expenses exceed annual revenue.
- 12) If a solution gas conservation project has an NPV less than –Cdn\$55 000 and is therefore considered uneconomic on its initial evaluation, the project economics must be re-evaluated annually (within 12 months of the latest evaluation) using updated prices, costs, and forecasts.

2.9.2 AER Economic Evaluation Audit Requirements

- 1) Economic evaluation audit packages submitted to the AER upon request must contain the following information in SI (international system of units) units:
 - a) detailed capital and operating cost schedules as set out in sections 2.9.1(6) and 2.9.1(7)

- b) oil and gas reserves calculations and supporting information (including a discussion of planned drilling programs and pressure maintenance schemes)
- c) a production forecast for both the oil and gas streams and the economic limit (date and production rates) of the project based on the oil production rate (including planned drilling programs and pressure maintenance schemes)
- d) a copy of the gas analysis from the project or a representative analog complete with gas heating value and gas liquid yields
- e) documentation of alternatives that were considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation
- f) documentation of compliance with the requirements listed in sections 7 and 8

2.10 Public Involvement

Licensees or operators with continuous solution gas flares, incinerators, or vents are expected to respond to questions or concerns raised by the public in relation to activities related to the flaring, incineration, and venting of solution gas at upstream petroleum industry facilities. To help respond to the public, public information packages should be prepared and provided. Licensees or operators must also meet consultation and notification requirements in *Directive 056*.

- 1) The licensee or operator must notify residents, schools, and the appropriate AER field centre of nonroutine flaring, incineration, and venting at production and processing facilities, as described in section 2.11, table 1.
- 2) The licensee or operator must meet minimum spacing requirements (see section 7.8).

2.10.1 Public Information Package

As a minimum, public information packages should include the following:

- 1) the definition of solution gas, and information on its conservation and use
- 2) an explanation of solution gas flaring, incineration, and venting management options and the decision tree process
- 3) a summary of analysis completed to determine that flaring, incineration, or venting is needed
- 4) information on general flare/vent performance requirements and reduction targets
- 5) descriptions of specific actions the licensee or operator will take to eliminate or reduce flaring, incineration, or venting or improve the efficiency of the flare, incinerator, or vent source based on the evaluation
- 6) a list of industry, AER, and government contacts that are related to public consultation and relevant to the project

2.11 Nonroutine Flaring, Incineration, and Venting at Solution Gas Conserving Facilities

The licensee or operator must minimize nonroutine flaring, incineration, and venting during upsets and outages of solution gas conserving facilities.

The AER also recommends that the licensee or operator contact the appropriate AER field centre for recommendations for minimizing solution gas flaring during outages at conserving facilities.

2.11.1 Limitations on Nonroutine Flaring, Incineration, and Venting During Outages at Solution Gas Conserving Facilities

- 1) Production operations must be managed to control nonroutine flaring, incineration, and venting of normally conserved solution gas in accordance with table 1 below.
- 2) Table 1 does not apply to nonassociated gas (the percentage cutbacks listed in table 1 apply to solution gas only). All nonassociated gas must be shut in during facility outages.
- 3) Emergency or plant upset shut in of production and reduction of solution gas inlet requirements in table 1 do not apply to thermal in situ production.
- 4) The licensee or operator must provide notification as required in table 1.
- 5) If there is a restriction to the plant inlet, the AER recommends that solution gas processing have priority over the processing of nonassociated gas in order to limit the unnecessary flaring of solution gas.
- 6) The AER recommends that wells with the highest GOR be the first to be shut in during facility outages and cutbacks.
- 7) Provided the overall required percentage reduction in solution gas production is achieved, it is not necessary to implement equal reductions at all locations upstream of the conserving facility outage.
 - a) When multiple licensees or operators are involved, they may determine how to best implement the overall required production reductions. If an agreement cannot be reached, each licensee and/or operator must reduce production as specified in table 1.

Table 1. Requirements during outage of a solution gas conserving facility

Shutdown category	Duration	Operational requirements
Partial equipment outages	< 5 days	Unless directed by the AER to flare, incinerate, or conserve all casing gas and tank top gas, shut-in of production is not required for equipment outages lasting less than 5 days that involve small volumes of gas (e.g., storage tank vapour recovery unit repair). This allowance is limited to a maximum of $2.0 \times 10^3 \text{ m}^3$ per day subject to limitation on venting as defined in section 8. If the event is ≥ 5 days, the operator must meet requirements stated below (planned shutdown category, >4 hours duration).
Planned	< 4 hours	The licensee or operator must make all reasonable efforts ¹ to reduce battery or solution gas plant inlet gas volumes by 50 per cent of average daily solution gas production over the preceding 30-day period.
	> 4 hours	<p>The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent of average daily solution gas production over the preceding 30-day period and meet the following requirements:</p> <ul style="list-style-type: none"> • Solution gas must not be flared from wells that have an H_2S content greater than 10 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily solution gas production, a variance must be obtained from the appropriate AER field centre (see section 2.11.3). • Residents within 500 m must be notified² at least 24 hours before the planned flaring event. • The AER also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate AER field centre must be notified³ 24 to 72 hours in advance if any of the following occurs: an event exceeds an approval condition; flaring has occurred that could potentially cause an adverse effect; the flared volumes exceed approved limits; flaring occurs that results in smoke or odours; the event extends over a long duration.
Emergency ⁴ or plant upset	< 4 hours	No reduction in the plant inlet is required.
	> 4 hours	<p>The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent of average daily solution gas production over the preceding 30-day period and must meet the following requirements:</p> <ul style="list-style-type: none"> • Solution gas must not be flared from wells that have an H_2S content greater than 10 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily production, a variance must be obtained from the appropriate AER field centre (see section 2.11.3). • Residents within 500 m must be notified² without delay about the flaring event. • The AER also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate AER field centre³ must be notified without delay if any of the following occurs: an event exceeds an approval condition; flaring has occurred that could potentially cause an adverse effect; the flared volumes exceed approved limits; flaring occurs that results in smoke or odours; the event extends over a long duration.
Repeat nonroutine flaring ⁵		The licensee or operator must investigate causes of repeat nonroutine flaring or venting and take steps to eliminate or reduce the frequency of such incidents.

Note: See appendix 2 for the definition of conserving facility.

¹ Notwithstanding solution gas reduction requirements listed in table 1, if a sour or acid gas flare or incinerator stack is not designed to meet the one-hour AAAQO for sulphur dioxide (SO_2) under high flow-rate conditions, action must be taken immediately to reduce gas to a rate compliant with the AAAQO (see section 7.12.5).

² Refer to section 3.8 (4) for resident notification requirements.

³ The appropriate AER field centre must be notified through the designated information submission system. In situations where limits have been exceeded, the appropriate AER field centre must be contacted by telephone before the designated information submission system is notified.

⁴ Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that causes the nonroutine flaring at the battery.

⁵ Repeat nonroutine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.

2.11.2 Planned Shutdown (Turnaround) Considerations

- 1) A licensee or operator must evaluate and implement appropriate measures to reduce solution gas flaring, incineration, and venting during a facility turnaround or planned shutdown. Alternatives that minimize impacts of planned shutdowns include
 - a) delivering solution gas to a nearby gas plant or facility that is not on turnaround;
 - b) scheduling maintenance at related oil facilities to coincide with the gas plant turnaround;
 - c) injecting solution gas into the gas cap of an oil pool or into a gas reservoir and producing it back when the gas plant is back on stream (see *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*); and
 - d) communicating with well, battery, and gas plant licensees or operators to ensure that nonroutine solution gas flaring, incineration, and venting are minimized.

2.11.3 Alternatives to Solution Gas Shut-in Requirements

The appropriate AER field centre will consider alternatives to the shut-in requirements listed in this directive for solution gas. This will be done only if the licensee or operator can demonstrate that shutting in a well or a group of wells may cause damage to well equipment or permanent reduction in productivity or if shutting in is impractical due to the remoteness of facilities. In these special cases, the licensee or operator must consult with the AER field centre about alternatives to shut in for a particular gas plant or battery.

- 1) A licensee or operator must plan for outages. If an alternative to table 1 is justified, the AER recommends that the licensee or operator submit a written request to the AER field centre at least 30 days before a planned shutdown explaining the alternative requested and giving supporting reasons for the request. The AER recommends that wherever possible, contact with the AER field centre not be deferred until an actual outage occurs.

2.12 Royalty Treatment of Flared and Vented Gas

In December 1998, the Government of Alberta created the Otherwise Flared Solution Gas Royalty Waiver Program to encourage the productive use of solution gas currently being flared. For more information, see Alberta Energy *Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program* available on Alberta Energy's [Natural Gas Royalty-Related Information](#) webpage.

The program is summarized as follows:

- The Alberta Department of Energy has developed criteria for ensuring that when gas can be economically conserved, it does not receive a royalty waiver.

- The program covers all methods of conserving solution gas.

2.13 Solution Gas Reporting Requirements and Data Access

2.13.1 Solution Gas Reporting Requirements

- 1) As per *Directive 007*, flared, incinerated, and vented solution gas must be reported monthly through Petrinex (Canada's Petroleum Information Network) as described in section 10.
 - a) Also as per *Directive 007*, a licensee or operator must report all new oil well production, including the test period, and obtain a battery code for any new oil wells before production, including flaring, can be reported (see *Directive 017: Measurement Requirements for Oil and Gas Operations*).

2.13.2 Cooperating with Third Parties

The AER recommends that the licensee or operator cooperate with qualified third parties attempting to conserve solution gas through open market or clustering efforts by providing nonconfidential information, such as gas analyses, flared and vented volumes, pressures, and other relevant data, on a timely basis (also see section 2.7).

In cases where conservation is determined by the licensee or operator to be uneconomic (as per section 2.8) but where a third party is able to conserve the gas, the AER recommends that the licensee or operator either conserve the gas or make the gas available at the lease boundary at no charge within three months of a request for the gas. It would be understood that this gas may be provided without processing or compression, and the third party must not affect the upstream operations.

Any third party requesting data from a licensee or operator must be technically qualified and have a reasonable expectation of proceeding with the gas conservation project. Third parties must also comply with all relevant AER requirements.

3 Temporary and Well Test Flaring and Incinerating

This section applies to temporary flaring and incineration activities. These activities include well testing, well cleanup, well servicing, sour gas pipeline (as defined in *Directive 056*) blowdown, coalbed methane well testing, underbalanced drilling, maintenance blowdowns, and emergency blowdowns through temporary or permanent flare or incinerator equipment.

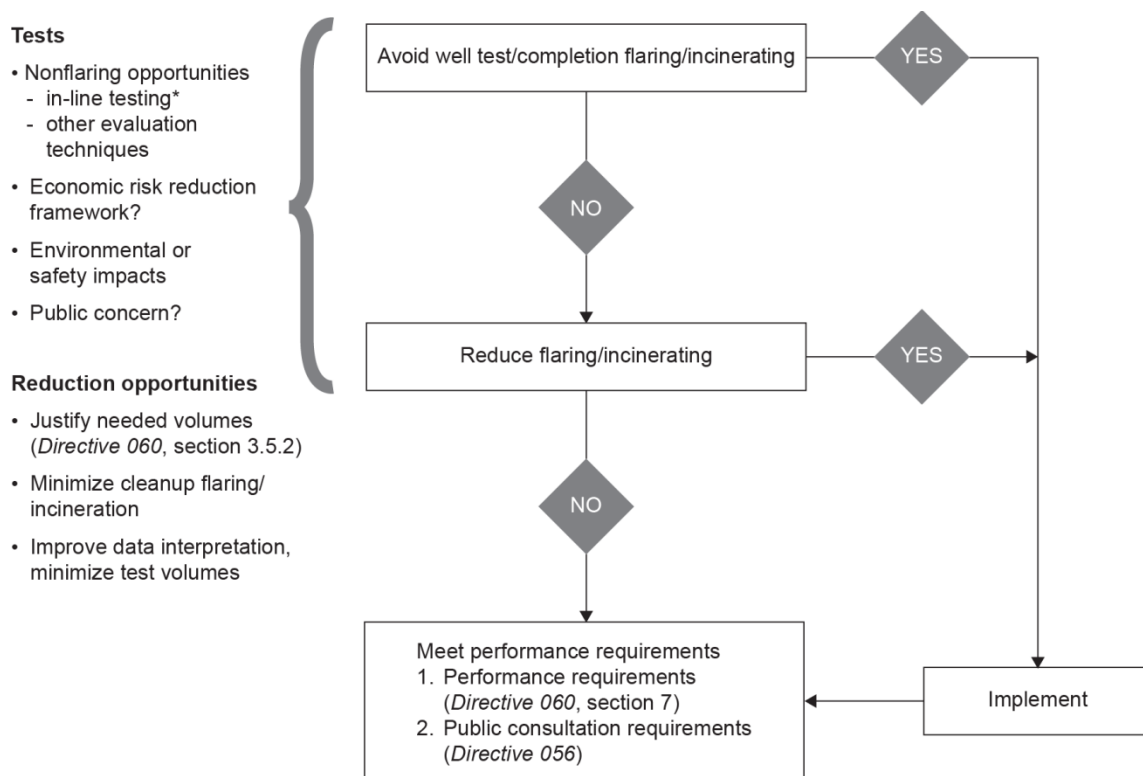
Unplanned nonroutine flaring and incinerating (e.g., process upsets, emergencies) do not require a temporary permit. Planned nonroutine flaring and incineration events (e.g., maintenance blowdowns, pipeline depressurizing, turnarounds) do require a temporary flaring or incineration permit, as stated in section 3.3.

The AER does not consider venting an acceptable alternative to flaring or incineration. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved. If venting is the only feasible alternative, it must meet the requirements in section 8.

3.1 Temporary Flaring and Incinerating Decision Tree

- 1) Licensees must use the temporary flaring and incinerating decision tree process (figure 3) to evaluate all opportunities to eliminate or reduce flaring and incineration, regardless of volume.
- 2) Licensees must evaluate opportunities to use existing gas gathering systems before beginning temporary maintenance, well cleanup, or testing operations (i.e., “in-line testing”). In-line testing must be done when economic and feasible to do so. Information on the evaluation of the most feasible option (e.g., closest potential tie-in location) must be provided with permit requests (section 3.5.1). The AER recommends that in-line testing be used in situations where
 - a) suitable infrastructure exists in proximity to the well and can be connected at moderate cost and where use of the infrastructure does not compromise integrity, or
 - b) sufficient productivity information is known about a development well so that connecting pipelines can be built with minimal financial risk before testing.
- 3) If in-line testing is not possible, licensees must design completions and well testing programs to minimize emissions while ensuring technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* must be consulted on the minimum pressure and deliverability requirements for well testing and on the recommended practices in order to ensure that the appropriate information is obtained for conservation and pool management purposes in addition to the requirements of this directive.

Licensees must use appropriate equipment and design temporary (maintenance, well completion, or test) programs to comply with performance requirements in section 7 and the *AAQO*.



*In-line testing may still involve very small quantities of flared or incinerated gas.

Figure 3. Temporary flaring and incineration decision tree (adapted from CASA)

3.2 Oil and Gas Well Test Flaring, Incinerating, and Venting Duration Limits

1) These time limits are per zone, are nonconsecutive, and do not include shut-in time. These periods include flaring, incinerating, and venting during cleanup, completion, workover, and testing. Licensees and operators must not exceed the following flaring, incinerating, and venting time limits:

- a) crude oil wells/sites:⁶ 72 hours
- b) bitumen wells/sites: until flow rates exceed an average of 900 m³/day for any consecutive three-month period, not to exceed six months. See section 2.4.
- c) gas (nonassociated, noncoalbed methane) wells: 72 hours
- d) dry coalbed methane development wells (producing less than 1 m³ of water per operating day): 120 hours
- e) dry coalbed methane nondevelopment wells (producing less than 1 m³ of water per operating day): 336 hours
- f) wet coalbed methane wells (producing more than 1 m³ of water per operating day): see section 3.2(7) below

⁶ A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.

- 2) Extensions to the time limits listed in (1)(a), (c), (d), and (e) above are allowed if any of the following are true:
 - a) Cleanup of the wellbore is not complete. Cleanup is considered complete when sand, proppant, or acid is no longer produced or when the gas composition meets the minimum pipeline specifications for the nearest pipeline that could accept the gas.
 - b) Stabilized flow has not been reached. Refer to *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*, section 4.3, and *Directive 034: Gas Well Testing, Theory and Practice*, section 7.1.
 - c) There have been mechanical problems with the well.
- 3) For extensions to the time limits stated in (1)(b) and (f), licensees must request approval from the AER as described in (5) below.
- 4) The licensee must document these reasons for extension and keep the information on file for review and/or audit by the AER field centre when requested. The licensee is not required to ask permission to extend the flaring/incineration beyond the specified time limit listed in (1)(a), (c), (d), or (e) if the reason matches those listed in (2)(a), (b), or (c), but must notify the appropriate AER field centre in advance through the designated information submission system as soon as the licensee recognizes that the time limit will be exceeded. The licensee must include reasons for the extension and the duration of the flaring, incinerating, and venting.
 - a) If an audited licensee fails to justify the need to exceed the time limitation to the AER field centre's satisfaction, the licensee may be subject to a regulatory response.
- 5) If more time for well test flaring, incineration, or venting is needed for reasons other than those listed above, the AER must be contacted for approval to continue as soon as possible, and no later than the end of the specified period.
- 6) If a temporary flaring/incineration permit has been issued, the volume allowed in the permit will take precedence over the time limit described in (1) above.
- 7) When well test information indicates that cleanup is complete and the well flow is stabilized and all other AER requirements (e.g., AER *Directive 040*) are met, flaring/incineration/venting must be discontinued, even if the time limit or the flaring/incineration permit volume has not been reached. This requirement does not apply to bitumen or wet coalbed methane wells. Timing requirements for bitumen are in section 2.4(2). Timing requirements for wet coalbed methane wells are in (8) below.
- 8) For wet coalbed methane wells producing more than 1 m³ of water per operating day, flaring/incinerating or venting must cease (gas must be conserved) within six months of gas production for an individual well exceeding a cumulative total of 100 10³ m³ for any

consecutive three-month period (about 1100 m³/day). Shorter tie-in periods must be pursued wherever possible.

- a) Licensees must notify the AER as soon as the cumulative total gas production exceeds 100 10³ m³ for any consecutive three-month period at a wet coalbed methane well that is flaring, incinerating, or venting.
- b) For wet coalbed methane wells that do not trigger the requirement above (i.e., 100 10³ m³ in 3 months), flaring, incineration, and venting are limited to the lesser of
 - i) a total period of 18 months, including the time to tie in the well, or
 - ii) a total cumulative volume of 400 10³ m³ for tier 2 (development) wells or 600 10³ m³ for tier 1 (other) wells per zone tested (see section 3.3.1[2]). Wells already tied in are treated as tier 3 and allowed a maximum cumulative flare, incineration, and vent volume of 200 10³ m³.
- c) If additional flaring/incineration or venting durations or volumes are needed to test a coalbed methane well producing more than 1 m³ of water per operating day, the licensee must make a written request to the AER as early as possible and in no case later than the end of the 18-month or volume allowance flare/incineration or vent period. Any request must include the reasons for the extension. Extensions may be granted to allow for additional flaring/ incineration/vent duration or volume for reservoir evaluations or if other special circumstances warrant.

3.3 Temporary Flaring/Incineration Permits

Figure 4 depicts the temporary flaring/incineration permit process.

The AER may suspend well flaring or incineration for noncompliance with conditions of the permit. The licensee must comply with the conditions of the temporary flaring permit.

3.3.1 Conditions That Require a Temporary Flaring/Incineration Permit

Note that an exemption for flaring small volumes of sour gas is found in section 3.3.2(2).

- 1) Licensees must obtain a permit to flare or incinerate sour gas containing more than 50 mol/kmol H₂S (5 per cent) or sour gas from any well classified as a critical sour well.
 - a) If operations result in H₂S concentrations that are higher than concentrations at the well (e.g., flaring gas from tanks), the composition of the gas to be burned must be determined in order to establish whether a permit is required. This composition must also be used in any required dispersion modelling.
 - b) If supplemental fuel gas is used, the resulting composition must be used for dispersion modelling. However, the gas composition from the source is still used as the basis for determining whether a permit is required.

- 2) Licensees must obtain a permit for temporary flaring or incineration of natural gas if gas well test volumes exceed the volume allowance threshold. This is based on the volume of gas flowed back from the well (and does not include fuel gas added, and volumes from vented nitrogen or carbon dioxide used in fracturing fluid).
 - a) The volume allowance threshold is defined in three tiers based on the volume of raw gas flowed back from the well (not including fuel gas added and carbon dioxide [CO₂] or nitrogen used for hydraulic fracturing). These volumes apply to gas well tests only:
 - i) **Tier 1 $\leq 600 \times 10^3 \text{ m}^3$** : applies to wells that have not been tied in and have a Lahee classification of new field wildcat (NFW), new pool wildcat (NPW), deeper pool test (DPT), or outpost (OUT).
 - ii) **Tier 2 $\leq 400 \times 10^3 \text{ m}^3$** : applies to wells that have not been tied in and have been assigned a Lahee classification (including development) not listed in the tier 1 allowance (excluding re-entry [REN] and experimental [EX] wells. See (b) and (c) below).
 - iii) **Tier 3 $\leq 200 \times 10^3 \text{ m}^3$** : applies to any well that has been tied in to facilities appropriately designed to handle production from the formation being tested (e.g., sweet versus sour service).

All requested volumes must be justified and may be questioned by the AER.

- b) The volume allowance threshold for a re-entry well is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as re-entry.
- c) For wells with a Lahee classification of experimental, the volume allowance threshold is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as experimental or that normally would have applied to the well had it not been classified as experimental.
- d) An incremental volume of $200 \times 10^3 \text{ m}^3$ may be added to the volume allowance threshold defined above for each additional zone being tested during continuous operations on a well (with continuous operations meaning that servicing equipment and personnel are not demobilized between tests on each zone), subject to the following limitations:
 - i) The volume flared from any zone during multiple-zone tests must not exceed the volume allowance threshold for a single zone unless a larger volume is specifically approved by the AER.
 - ii) The incremental allowance does not apply to single tests over multiple commingled zones. Each zone to be tested must be identified and fully accounted for in the related flare permit request.

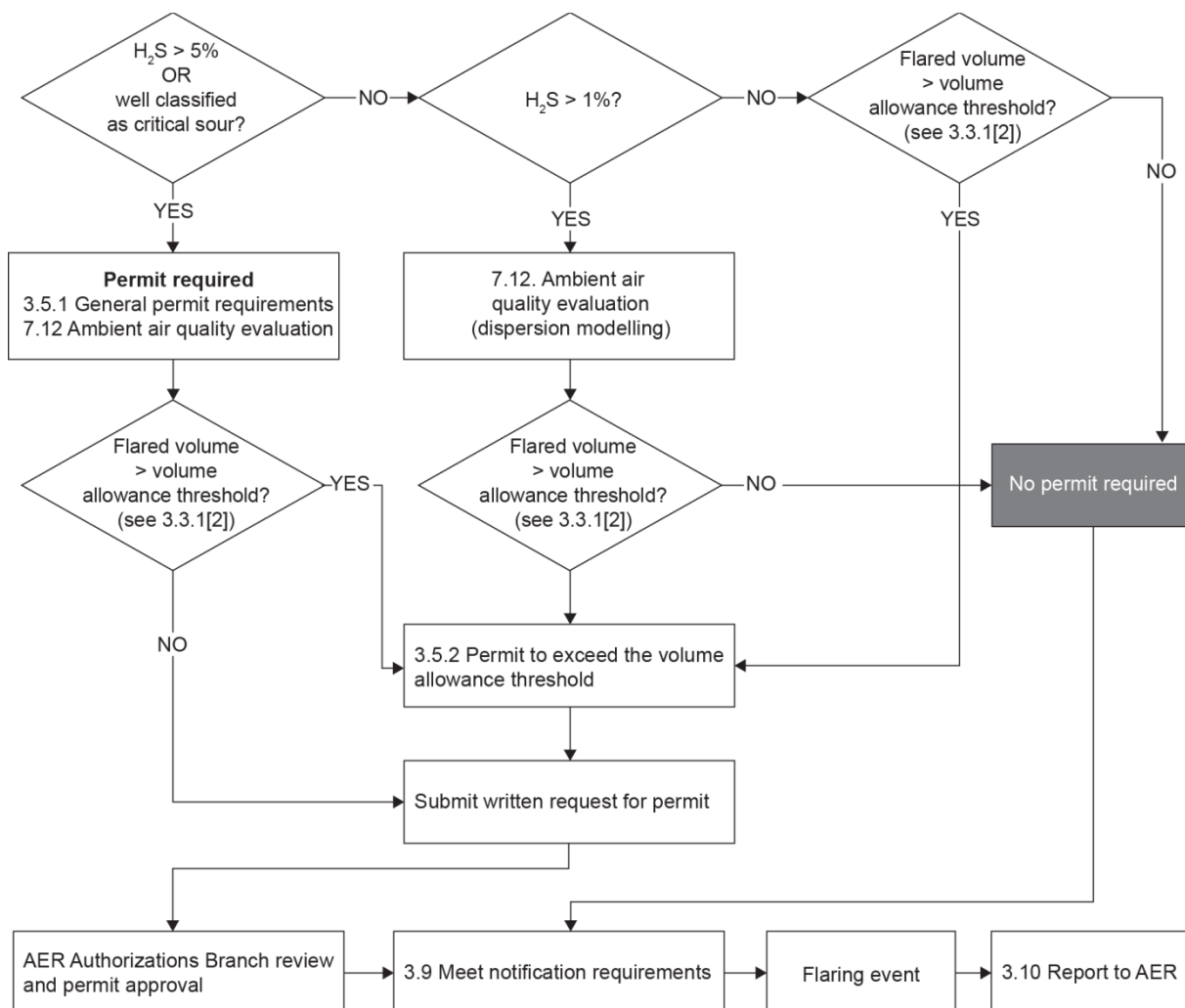


Figure 4. Temporary flaring/incineration permit process

3.3.2 Conditions That Do Not Require a Temporary Flaring/Incineration Permit

- 1) A permit is not required if the gas contains 50 mol/kmol H₂S (5 per cent) or less and the total volume (for gas well tests) is less than the volume allowance threshold (see section above). However, licensees must meet the requirements in section 3 and section 7, as well as the notification requirements in section 3.8.
 - a) Licensees must evaluate compliance with the one-hour *AAQO* for SO₂ if the gas contains more than 10 mol/kmol H₂S (1 per cent). Related dispersion modelling results must be provided to the AER upon request.
- 2) Flaring or incinerating small volumes of sour gas containing more than 50 mol/kmol H₂S (5 per cent) are exempt from AER permit requirements provided that the following conditions are met:
 - a) Maximum sulphur emission rates do not exceed 1.0 tonne/day over the duration of the event.

- b) Total flared or incinerated volume do not exceed $50 \times 10^3 \text{ m}^3$ over the duration of the event.
 - c) Equipment is designed to ensure compliance with the one-hour *AAQO* for SO_2 or operating procedures are in place to ensure compliance with the *AAQO*. Related dispersion modelling evaluations and design information are documented and available to the AER upon request.
 - d) Rates and volumes are measured and reported as defined in section 10.
 - e) Written notification is provided to the AER. Notification includes total expected gas volumes and sulphur emissions. If applicable, notification provides an explanation of any air quality management plans needed to ensure compliance with the *AAQO*.
- 3) The AER does not require temporary permits for the use of permanent flares or incinerators installed in AER-licensed facilities, including batteries, compressor stations, and gas plants provided that licensees can show, on request from the AER or field centre staff, that
- a) the flaring or incineration volumes, rates, and gas composition are within the limits of the facility licence;
 - b) the flares or incinerators are designed to operate safely under the intended conditions in compliance with the *AAQO*; and
 - c) the total volumes are less than the volume allowance threshold.
- 4) Similarly, the AER does not require temporary permits for unplanned nonroutine events such as emergencies. Licensees must ensure that temporary nonroutine systems are adequately designed to operate safely under anticipated emergency and upset conditions and meet the requirements in section 7.
- a) For planned nonroutine events, including maintenance blowdowns, pipeline depressurizing, and turnarounds, licensees must obtain a temporary permit if required by section 3.3.1, unless exempted in (2) or (3) above.
- 5) The AER does not require temporary permits for flaring at oil and bitumen batteries. The operator must meet conservation requirements described in section 2.

3.4 Flaring and Incineration Permits for Underbalanced Drilling

Permit requirements (section 3.3) and notification requirements (section 3.8) for temporary flaring and incineration also apply to underbalanced drilling.

For more detail on underbalanced drilling requirements, see appendix 5.

3.5 Permit Requirements for Temporary Flares and Incinerators

Figure 4 summarizes the temporary permit process.

3.5.1 General Permit Requirements

- 1) Requests for temporary permits must be submitted to the AER via email (Directive060Inbox@aer.ca) and must include complete information on the proposed activity, as requested in the AERflare.xls and AERincin.xls spreadsheets (available on the AER website) and summarized as follows:
 - a) a cover letter requesting a permit and informing the AER of any public objections to or concerns about the proposed flaring/incineration
 - b) information about the site on which flaring/incineration will occur, including location, Lahee classification, and related National Topographical System 1:50 000 scale maps
 - c) an evaluation of the most feasible option for in-line testing
 - d) information on planned flaring/incineration, including reasons (e.g., well testing, completions, pipeline depressurizing), H₂S content, flow rates, total volumes, and type of combustion device to be used (i.e., flare or incinerator)
 - e) information on the licensee's assessment of effects on ambient air quality, including results of dispersion modelling for SO₂
 - f) in situations with potential to exceed the risk-based criteria (see section 7.12.4) for SO₂, information on the licensee's proposed air quality management plan to prevent exceedances
- 2) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee. Permit requests are processed in the order received, and resubmissions will be treated as new permit requests.
- 3) Temporary permit requests can be submitted electronically by the licensee. A permit will be in the name of the licensee.

3.5.2 Requests to Exceed the Volume Allowance Threshold

Information requirements apply to all requests to exceed the volume allowance threshold. However, any volume of gas flared or incinerated must be defensible.

- 1) Licensees must provide specific engineering, economic, and operational information to justify flaring or incinerating gas volumes in excess of the volume allowance threshold.
- 2) All requests for volumes greater than the volume allowance threshold regardless of H₂S content must be submitted to the AER (email Directive060Inbox@aer.ca) and must include the following, in addition to information in section 3.5.1 (note that 1[e] and [f] of that section do not apply to sweet gas wells).

- a) Requests relating to tests to determine if enough gas supply exists to justify related investments must include information on the scope of development required to produce the well and necessary threshold reserves. (See appendix 5).
 - b) Requests relating to tests to determine the relationship between absolute open flow (AOF) and deliverability of the well must include justification of the volume being requested as it pertains to obtaining an accurate deliverability relationship, in accordance with AER *Directive 040*.
 - c) Requests relating to tests to establish the stabilized flow rate of the well must include justification of the flare volume request as it pertains to obtaining a stabilized flow rate, including identification of any analogous wells being used for comparison purposes.
- 3) Should the information described above not be available or applicable, licensees must include discussion on why it is not included with the exceedance request.
 - 4) For underbalanced drilling, follow the guidelines in appendix 5.

3.5.3 Blanket Flaring/Incineration Permits

Sour oil and gas well operations such as well servicing may result in flaring of relatively small volumes of gas at several sites in a local area. To simplify temporary permit request requirements, the AER may issue a single “blanket” permit to cover several flaring events at different sites in an area if so requested by the licensee. Blanket permit request requirements and limitations are as follows:

- 1) Blanket permits are issued on a fixed-term basis for periods not to exceed one calendar year. Licensees must complete and submit a new flare permit request to renew blanket permits for additional periods of time.
- 2) Blanket permits are limited to specific stack heights, locations, rates, maximum volumes per event, maximum H₂S concentrations, and maximum sulphur emissions per event as listed in the permit request.
- 3) All wells must be licensed before they can be considered for a blanket permit.
- 4) For every well being considered for a blanket permit, licensees must use the AERflare.xls or AERincin.xls spreadsheet (available on the AER website) to evaluate the temporary flaring or incineration parameters during the period in which flaring/incineration is planned.
 - a) The spreadsheets provide screening modelling. Refined modelling may be required and must meet the risk-based criteria.
 - b) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee.
- 5) A blanket permit will not be considered if

- a) projected volumes are greater than $100 \times 10^3 \text{ m}^3$ per site or flaring event;
- b) total sulphur emissions will exceed 10 tonnes per event;
- c) an air quality management plan is necessary for compliance with the risk-based criteria for SO_2 ; or
- d) complex terrain modelling is required for specific locations.

Exceptions may be made only after consultation with the AER.

- 6) A list of wells and their bottomhole and surface locations and licence numbers must be submitted to the AER before a blanket permit request will be considered.
- 7) A sour gas flaring/incineration data summary report (see appendix 6) for each well must be completed and submitted to the AER within 30 days of the end of each calendar quarter-year.

If no flaring or incineration was done over the previous calendar quarter-year, a sour gas flaring/incineration data summary report on the lack of flaring or incineration must be submitted.

- 8) Licensees must comply with public and AER field centre notification requirements for each flare event covered by the blanket permit, as described in section 3.8.

3.5.4 AER Review of Permit Requests

Requested volumes, rates, or conditions may not be granted by the AER. Consideration will be given to total volumes, total sulphur emissions, local land uses, proximity of residences, and potential for exceedance of the *AAQO* before a permit is granted. AER staff will consult with licensees in such situations.

- 1) Licensees must avoid temporary flaring or incineration in situations where existing infrastructure can be reasonably used for in-line disposition of the gas, especially in populated areas.
- 2) Licensees must limit the volumes for gas that they request, especially gas with high H_2S contents. Situations involving sulphur emissions of 50 tonnes or more are subject to closer scrutiny by the AER. The AER typically will not approve permits where total sulphur emissions exceed 300 tonnes.

3.6 Site-Specific Requirements Related to Well Flaring and Incineration

The following requirements apply to the use of temporary flares and incinerators.

- 1) Temporary flares and incinerators must comply with design and operation requirements defined in section 7.

- a) Flares and incinerators must not be operated outside design operating ranges as specified by the designing or reviewing qualified technical professional who is a member of the Association as defined in the *Engineering and Geoscience Professions Act*.⁷
- 2) Licensees must determine the H₂S content of flared or incinerated gas using Tutweiller or gas chromatography methods as soon as is practical after beginning operation if gas analysis has not been done within the preceding 12 months.
- 3) If the H₂S content in the gas is found to exceed 50 mol/kmol H₂S and no flaring or incineration permit has been issued by the AER, or if the H₂S content of the gas exceeds the maximum value listed in the related permit, operations must be suspended and the appropriate AER field centre notified. Operations must not resume until a permit or permit amendment is issued by the AER in response to a written request.
- 4) Both high- and low-pressure gas-liquid separation stages must be used for sour gas to minimize vapour released from produced hydrocarbon liquid and sour water storage.
- 5) Liquid storage must be designed to prevent the escape of sour gas to the environment. For more detail, see the most current edition of *Industry Recommended Practice [IRP] Volume 4: Well Testing and Fluid Handling* from the Canadian Petroleum Safety Council.

3.7 Temporary Facilities for In-Line Tests

To facilitate conservation, the licensee or operator may install a temporary compressor and pipeline connections. For temporary compressor installation, see *Directive 056*.

Section 3.7 of this directive does not apply to oil batteries. However, *Directive 056* application requirements apply to both temporary and permanent oil batteries.

- 1) Details on application requirements and exceptions for temporary well test facilities and pipeline connections are in *Directive 056*. In the case of a discrepancy between this directive and *Directive 056*, *Directive 056* application requirements apply.
- 2) Exceptions to AER applications requirements for temporary facilities, such as temporary connection to existing gathering systems, are intended to encourage conservation of gas associated with well testing. The provisions do not apply to testing situations in which gas will be flared.
- 3) Only one test period will be approved at each site. If there are multiple events, an application is required (see *Directive 056*).
- 4) For extended tests or multiple tests that require temporary facilities to operate for more than 21 days, the licensee or operator must complete an application (see *Directive 056*).

⁷ *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

- 5) Proposals to install temporary compressors and other facilities for reasons other than testing new wells must comply with *Directive 056* application requirements.
- 6) Any licensee or operator intending to use temporary production, compression, and/or pipeline facilities must notify the appropriate AER field centre and obtain approval for a variance from *Directive 056* application requirements.
 - a) The notification must include a description of the proposed equipment (including relevant capacities), driver type, and layout (e.g., give the compressor power rating and note whether the driver type is gas, diesel, or electric).
 - b) A licensee or operator intending to install and use temporary pipelines for well testing must complete and submit to the appropriate AER field centre the Checklist for 21-Day Temporary Surface Pipelines for Well Testing Purposes.⁸
 - c) AER field centre approvals for temporary facilities are valid for 21 days and include the dismantling and removal of temporary facilities (including pipelines) from the lease. Any exceptions, including allowances for downtime during testing, must be referred to the appropriate AER field centre for further review.
- 7) Temporary facilities, including pipelines, must comply with relevant AER requirements.
 - a) Temporary facilities must meet noise control requirements defined in *Directive 038: Noise Control*.
 - b) The licensee or operator must meet emergency response plan requirements for sour wells. The plan must incorporate provisions for the temporary equipment, as appropriate. See *Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry*.
- 8) Temporary sweetening processes, if used, must be of the zero-sulphur-emissions type. The licensee or operator must submit a facility application, as described in *Directive 056*, for temporary installation of regenerative sweetening processes with acid gas.
 - a) All temporary or permanent regenerative sweetening facilities require an AEP sour gas processing plant approval.
- 9) Temporary pipelines and batteries must comply with *Directive 056* public consultation requirements.

3.8 Notification Requirements

Unless the licensee, operator, or approval holder reaches, with the people who require notification in accordance with this directive, an agreement that provides for an alternate means of notification, the licensee, operator, or approval holder must provide notice of flaring, venting,

⁸ Available on the *Directive 056* page of the AER website, www.aer.ca.

or incineration in accordance with this directive. The AER does not require the licensee, operator, or approval holder to obtain the consent of residents within the notification radius.

- 1) The licensee, operator, or approval holder must notify all residents and schools of flaring, incineration, and venting in accordance with table 2. The notification distances in table 2 are minimum requirements.
- 2) Notice must be given to the appropriate AER field centre via the designated information submission system of any planned flaring, incineration, or venting at least 24 hours in advance.
 - a) Notice to the appropriate AER field centre must include a contact name and telephone number in case of complaints or emergencies.

Table 2. Temporary flaring, venting, and incineration notification requirements¹

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

¹ See section 1.6 for information on the designated information submission system and how to notify the appropriate AER field centre via the system.

² Notification requirements include duration and volume from flowback operations. These gases may be hydrocarbon or gases used in fracturing fluids (carbon dioxide or nitrogen) in any mixture. For reporting purposes, hydrocarbon volumes must be distinguished from fracture gas volumes (see section 3.9).

³ 24 to 72 hours in advance of planned flaring, venting, or incineration operations, the licensee, operator, or approval holder must notify the appropriate AER field centre via the designated information submission system, all rural residents outside towns, villages, and urban centres and within the specified radius, and the chief administrative officer or equivalent of a town, village, or urban centre within the specified radius. Note that for incorporated centres and hamlets, it is sufficient to contact only the appropriate administrator. Advance notification of more than 72 hours (but not longer than 90 days) must also offer the option for renotification 24 to 72 hours before the start of operations. After 90 days, renotification is mandatory.

⁴ The AER recommends additional "good neighbour" notification for short-duration events for residents and schools that have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility within the same notification radius as specified for events of more than four hours.

⁵ The AER recommends additional "good neighbour" notification for longer duration events (of more than four hours) for residents and schools that have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility.

- 3) Upon AER field centre request, the licensee, operator, or approval holder must provide a list of residents and schools notified within the specified notification radius, as well as a sample of the information provided to residents.
- 4) Unless the licensee, operator, or approval holder has reached an agreement with current residents or schools for an alternative method of notification, notification must be in writing (see appendix 9) and include the following basic information about the flaring, incineration, or venting:
 - a) licensee, operator, or approval holder's name, contact persons, and telephone numbers
 - b) the location of the flaring, incineration, or venting
 - c) the duration of the event (start date and expected completion date)
 - d) the expected event volume and rates
 - e) information on the type of well (oil, gas, or coalbed methane) and, if applicable, information on the H₂S content of the flared or incinerated gas
 - f) AER field centre contact telephone number
- 5) The licensee, operator, or approval holder may conduct a one-time notification program for multiple-well projects in an area unless the licensee, operator, or approval holder has reached an agreement with current residents or schools for an alternative method of notification. In addition to the information above, the related multiple-well project notification must provide
 - a) the locations where flaring, incineration, or venting will occur,
 - b) the period during which the project will be carried out, and
 - c) the expected duration and volume of temporary flaring, venting, or incineration.
- 6) The licensee, operator, or approval holder may limit the number of repeat notifications to individual residents or schools if
 - a) the resident or school requests that the number of notifications be reduced;
 - b) the licensee, operator, or approval holder provides the resident or school with an outline of expected flaring and incineration activities in the area; and
 - c) the licensee, operator, or approval holder has a written agreement to reduce notifications and obtains acceptance of the agreement in writing from the resident or school. A copy of this written agreement must be provided to the AER upon request.
- 7) The licensee, operator, or approval holder may conduct a single notification to each resident and school within the notification area and the appropriate AER field centre, rather than a separate notification for each flaring, venting, or incineration period throughout the program, if this is acceptable to the current residents. The method of notification must be discussed during the initial notification process.

- 8) The AER recommends that the licensee, operator, or approval holder consider placing signage on public roads surrounding the temporary flaring or incineration operations indicating the operation type and the contact phone number for inquiries.

3.8.1 Addressing Resident Concerns

Compliance with *Directive 060* ensures that licensees, operators, and approval holders have considered public safety and environmental impacts before flaring, incineration, and venting activities; however, additional concerns or complaints may be expressed by nearby residents or schools regarding impacts of the operational aspects of flaring or incineration (e.g., timing of flaring and associated traffic). The following ensure that concerns of nearby residents and schools are addressed:

- 1) The AER encourages the licensee, operator, or approval holder to work with nearby residents and schools prior to commencing proposed and existing flaring or incineration activities.
- 2) The licensee, operator, or approval holder must immediately disclose any unresolved concerns of nearby residents and schools about those activities to the appropriate AER field centre in order to discuss concerns or complaints related to those activities.
- 3) Residents and schools may subsequently contact the appropriate AER field centre to discuss concerns or complaints related to those activities.

The AER may work further with the licensee, operator, or approval holder to modify one or more operational aspects of the proposed or existing flaring or incineration activities to address the concerns of nearby resident and schools, but it will not suspend flaring or incineration activities in response to a concern or complaint unless there is clear evidence that the licensee, operator, or approval holder is not in compliance with *Directive 060*.

3.8.2 AER Flaring/Incinerating/Venting Notice Form

- 1) To comply with the requirements in section 3.8 above, the licensee, operator, or approval holder must complete the AER flaring/incineration/venting notice form in the designated information submission system and submit it electronically to the appropriate AER field centre.

3.9 Reporting Gas Well Test Data

- 1) Well test results and information required by flaring and incineration permits must be submitted in accordance with the requirements of *Directive 040*, the applicable permit, and section 10.
 - a) All well test reports must be submitted within three months of completing the fieldwork. This information must include the volume of gas produced to flare, vent, or pipeline, as well as all gas analyses from samples gathered at the wellhead. Submissions must be in

a pressure ASCII standard (PAS) format and submitted via the well test data capture system in the designated information submission system. For questions on these submissions, email the well test help line at Welltest-Helpline@aer.ca.

- 2) For all well tests that require permits, a sour gas flaring/incineration data summary report must be submitted to the AER within three weeks of the completion of flaring or incineration (see section 10.1, appendix 6, and AERflare.xls or AERincin.xls spreadsheet).
- 3) All flaring, incineration, and venting at a well site (including well tests) must be reported on the appropriate production reporting submissions, including Petrinex (see *Directive 007: Volumetric and Infrastructure Requirements*).

3.10 Zero Flaring Agreements

Flaring is allowed by the AER when done in accordance with *Directive 060*. However, parties may agree to zero flaring, as set out in a zero flaring agreement (see appendix 10). The agreement must be signed by both parties and filed by the applicant with the well application. Once filed, the zero flaring agreement becomes a condition of the well licence. Should the licensee, operator, or approval holder fail to adhere to this agreement, operations at the well may be suspended. This agreement, including the condition, expires when production begins.

Once the well or facility is licensed, if the licensee, operator, or approval holder needs to change this zero flaring agreement, it must file an application to change the agreement with the AER, with a copy to the co-signers.

- 1) An application to change a zero flaring agreement must include
 - a) the reasons that the agreement needs to be changed,
 - b) a copy of the original application and approval,
 - c) a copy of the original and revised zero flaring agreement, and
 - d) a summary of the consultation and notification that have been done, including confirmation of agreements reached with the parties affected by this agreement.

Until the AER decides on this application, flaring may only occur as set out in the zero flaring agreement. For oil wells, agreement not to flare during well testing means that the licensee, operator, or approval holder has agreed to initially conserve the gas. Later, if it becomes uneconomic to conserve the gas, the licensee, operator, or approval holder must follow the process in section 2.6(6) of this directive to discontinue conservation.

The licensee, operator, or approval holder must try to address the landowner or occupant concerns and may use the AER's alternative dispute resolution process if that becomes necessary before applying with the AER to change this zero flaring agreement.

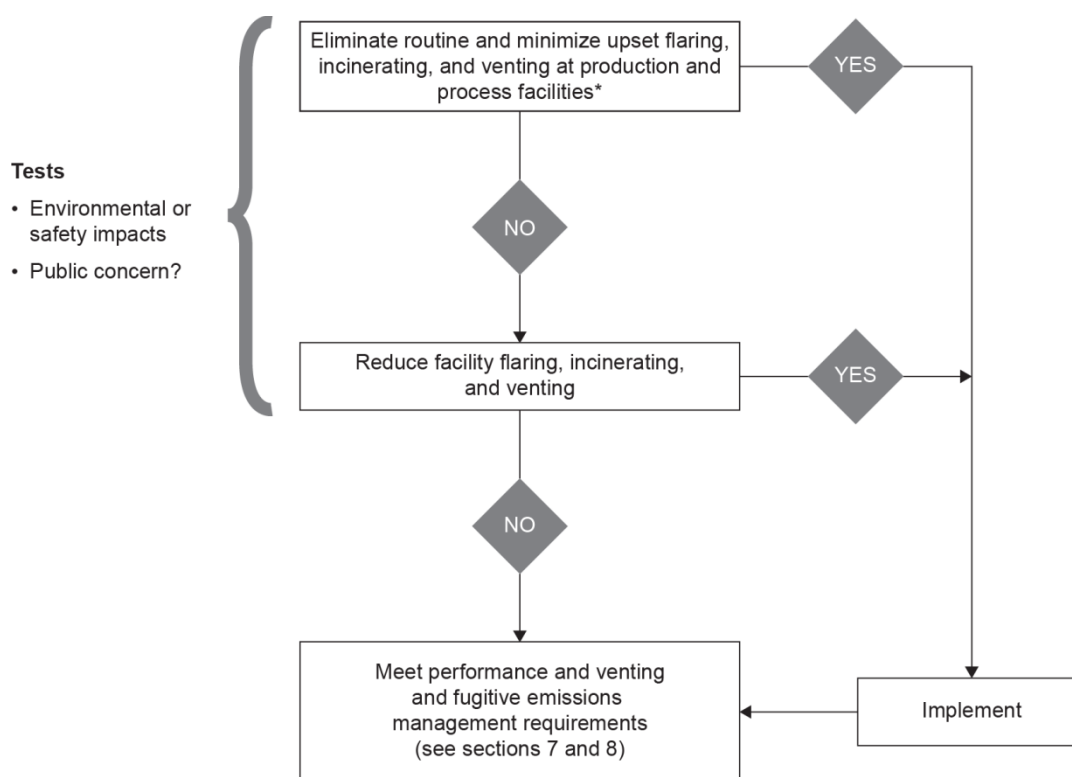
4 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting

This section addresses gas battery, dehydrator, and compressor station flaring, incinerating, and venting and includes

- routine flaring and incineration, and
- nonroutine flaring, incineration, and venting for equipment depressurization for maintenance; process upsets; and emergency depressurizing for safety reasons.

4.1 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting Decision Tree

- 1) The licensee or operator must use the decision tree analysis shown in figure 5 to evaluate all new and existing gas battery, dehydrator, and compressor station flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m³ per month) such as pig trap depressurizing.



* This does not apply to emergency situations.

Figure 5. Facility flaring, incinerating, and venting decision tree (adapted from CASA)

- 2) The licensee or operator must document alternatives that were considered in order to eliminate or reduce flaring, incineration, and venting, how they were evaluated, and the outcome of the evaluation.

- 3) New batteries proposing routine flaring, venting, or incineration must be evaluated before application as part of the facility design. All existing batteries with routine sources were required to have been evaluated by December 31, 2004.
- 4) The licensee or operator must assess opportunities to eliminate or reduce nonroutine flaring, incineration, and venting of gas due to frequent (i.e., one event per month) maintenance or facility shutdowns.
 - a) The licensee or operator must investigate and correct frequent nonroutine events at gas batteries.
 - b) The licensee or operator must address concerns or objections of residents and schools related to nonroutine gas battery flaring.
- 5) Flare, incinerator, and vent systems must be designed and operated in compliance with sections 7 and 8, good engineering practice, and any other safety codes and regulations required by other agencies.

4.2 Notification

- 1) The licensee or operator must notify residents, schools, and the appropriate AER field centre of nonroutine flaring at gas batteries as follows:
 - a) If gas battery flaring exceeds four hours in duration, the licensee or operator must notify residents and schools as described in section 3.8 and table 2.
 - b) If a gas battery flaring event exceeds $30 \times 10^3 \text{ m}^3$ and/or four hours in duration or is likely to cause concern for residents or schools, the appropriate AER field centre must be notified (see table 2).
- 2) The licensee or operator must give the AER field centre at least 24 hours' notice of planned gas battery outages and turnarounds that will result in flaring of more than $30 \times 10^3 \text{ m}^3$ or for more than four hours duration. The licensee or operator must give residents and schools notification without delay or as soon as practical of unplanned gas battery outages that result in flaring of more than $30 \times 10^3 \text{ m}^3$ or for more than four hours.

4.3 Reporting

- 1) All monthly flared and vented volumes must be reported separately on Petrinex in accordance with sections 8 and 10 and *Directive 007*. Incinerated volumes must be combined with and reported as flared volumes.
- 2) Gas burned in an incinerator must be reported as flared. Fuel gas burned in an incinerator must be reported as flared.
- 3) Gas flared or vented at gas batteries must be reported at the flaring or venting location. For facilities that do not require a licence (such as small booster compressors), the flared and vented volumes must be reported at the nearest upstream reporting well, battery, or pipeline facility.

5 Gas Plant Flaring, Incinerating, and Venting

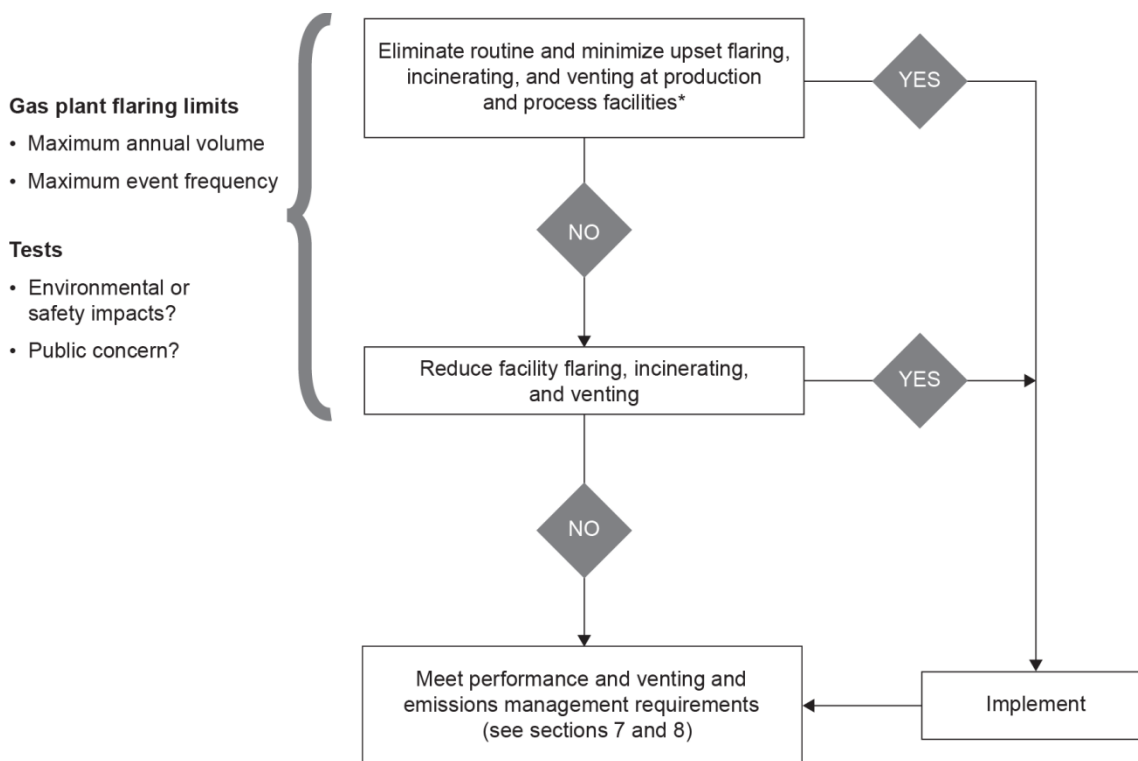
This section addresses disposal of gas from gas processing plants by flaring, incinerating, and venting. Sources of natural gas flaring, incineration, and venting at gas production facilities include

- routine flaring, incineration, and venting of low-pressure flash-gas and other gas streams, and
- nonroutine flaring, incineration, and venting for equipment depressurizing for maintenance process upsets, and emergency depressurizing for safety reasons.

5.1 Gas Plant Flaring, Incinerating, and Venting Decision Tree

Licensees must use the decision tree analysis shown in figure 6 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 depressurizing. Furthermore, these evaluations must be updated annually or when changes at the plant materially change plant operation.

- 1) Licensees must document alternatives that were considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation.
- 2) Licensees must assess opportunities to eliminate or reduce nonroutine flaring, incineration, and venting of gas due to frequent maintenance or facility reliability outage, as well as
 - a) address concerns and objections of residents and schools notified in accordance with table 2 related to nonroutine flaring, and
 - b) comply with the limitations on total flared, incinerated, and vented volumes and the number of repeat events defined in sections 5.2 and 5.3.
- 3) Flare, incinerator, and vent systems must be designed and operated in compliance with sections 7 and 8, good engineering practice, and any other safety codes and regulations required by other agencies.
 - a) Gas streams directed to continuous gas plant flares must have a minimum heating value as defined in section 7.1.1.
 - b) All existing plants were required to have performance evaluations completed by December 31, 2004.



* This does not apply to emergency situations.

Figure 6. Facility flaring, incinerating, and venting decision tree (adapted from CASA)

5.2 Gas Plant Flaring/Incineration/Venting Volume Limits

The AER limits the total annual volume of gas disposed of by flaring, incineration, and venting at gas processing plants. Acid gas volumes from gas sweetening (which are normally continuously flared) are excluded from the following limits:

- 1) For gas plants processing more than $1.0 \times 10^9 \text{ m}^3$ per year (raw gas inlet volume), flaring, incineration, and venting must not exceed the greater of 0.2 per cent of raw gas receipts or $5.0 \times 10^6 \text{ m}^3$ per year.
- 2) For gas plants processing less than or equal to $1.0 \times 10^9 \text{ m}^3$ per year (raw gas inlet volume), flaring, incineration, and venting must not exceed 1.0 per cent of raw gas receipts in the first year of operation and must not exceed 0.5 per cent of raw gas receipts in any subsequent year with the following exception:
 - a) For acid gas plants processing less than or equal to $0.1 \times 10^9 \text{ m}^3$ per year (raw gas inlet volume), flaring, incineration, and venting must not exceed 3.75 per cent of raw gas receipts in any year of operation.
- 3) If multiple flare stacks are available in gas production, gathering, and processing systems, licensees must use the flare stack that is the most efficient and capable of providing the best dispersion. In most cases this would be the gas plant flare stack.

- a) Licensees can deduct solution gas flared at gas plants during plant shutdowns lasting more than seven days in calculating the annual flared volumes applicable to (1) and (2) above. These solution gas volumes must be documented and provided to the AER upon request.
- 4) Licensees must comply with the solution gas reduction limitations in section 2.11 during facility outages.
- 5) As per section 2.11.1, all nonassociated gas must be shut in during facility outages.
- 6) The AER recommends that solution gas processing take priority over the processing of nonassociated gas.

5.3 Frequent Nonroutine Flaring/Incineration/Venting Events

- 1) Licensees must investigate and correct causes of repeat nonroutine flaring, incineration, and venting.
- 2) Gas plants must not exceed six major nonroutine flaring events in any consecutive (rolling) six-month period (6-in-6). Major flaring events are defined in table 3.

Table 3. Major flaring event definition

Approved plant inlet capacity	Major flaring event definition*
>500 10 ³ m ³ /d	100 10 ³ m ³ or more
150–500 10 ³ m ³ /d	20 per cent of plant design daily inlet or more
<150 10 ³ m ³ /d	30 10 ³ m ³ or more

* The definition of a flaring event includes situations where

- volumes greater than or equal to those specified in the table are flared in any single day; each day that specified flared volumes are exceeded is considered to be a separate, individual event; or
- volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (e.g., flaring for four days at a continuous rate of 25 10³ m³/d is considered one event).

- 3) Licensees must log and monitor nonroutine flaring events, as required in section 10.1. Major flaring events must be flagged. The following applies if a sixth major flaring event occurs within any consecutive (rolling) six-month period:
 - a) Licensees must submit a written “exceedance” report to the appropriate AER field centre and copy this report to the AER within 30 days of the occurrence of the sixth flaring event.
 - i) The exceedance report must provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and on their possible causes.
 - ii) The report must also propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major nonroutine flaring does not recur.

- b) Licensees must obtain AER field centre approval of the proposed plan referred to in 3(a)(ii) above.
 - i) If facility modifications are proposed in the plan and approvals are required by *Directive 056*, AER Authorizations approval must be obtained before implementing any such actions.
 - ii) Upon AER field centre approval of the plan, including facility modifications, licensees are expected to expedite schedules for implementing the plan.
- c) After the plan implementation date, the AER may issue a regulatory response if another exceedance of the 6-in-6 criterion occurs within 24 months.

5.4 Notification

- 1) Licensees must notify residents, schools, and the appropriate AER field centre of nonroutine flaring at gas plants (see table 2).
 - a) The appropriate AER field centre must be notified if a nonroutine flaring event exceeds $30 \times 10^3 \text{ m}^3$, exceeds four hours' duration, or is likely to cause public concern.
 - b) Licensees must provide the appropriate AER field centre with at least 24 hours' notice of a plant turnaround.
 - c) The appropriate AER field centre must be notified 24 to 72 hours before planned flaring and as soon as practical of unplanned flaring when notification is required.

5.5 Measurement and Reporting

Measurement and reporting requirements for gas plants include the following:

- 1) All monthly flared and vented volumes must be reported separately on Petrinex in accordance with section 10 and *Directive 007*.⁹
- 2) Flaring of sour gas must also be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report (see section 11 of *Directive 017*).
- 3) When metering is not required, engineering estimates must be used to report any flared gas not measured (see section 10).
- 4) Licensees must provide a documented system for metering and/or estimating flared and vented gas volumes (as defined in sections 8 and 10) upon AER request. All flare events both minor and major must be logged (in accordance with section 10.1) and provided upon request.

⁹ This information is summarized annually in AER ST13A: *Alberta Gas Plant/Gas Gathering System Activities—Annual Statistics*, and monthly in ST13B: *Alberta Gas Plant/Gas Gathering System Activities—Monthly Statistics*, and ST13C: *Alberta Gas Gathering System Activities—Monthly Statistics*.

- 5) Gas that is flared or incinerated must be reported as flare gas.
- 6) Licensees must monitor and minimize gas used for flare header purges, flare pilots, and incinerator pilots.
 - a) Licensees must be able to justify gas usage volumes.
 - b) The AER may require evidence of this justification on the basis of case-specific audits and inspections.

6 Pipeline Flaring, Incinerating, and Venting

This section addresses disposal of gases from gas gathering and transmission lines by flaring, incineration, and venting. Sources of gas flaring, incineration, or venting include

- routine flaring, incineration, and venting of low-pressure flash-gas and other gas streams at pipeline system compressor and dehydration facilities, and
- nonroutine flaring, incineration, and venting for pipeline depressurizing for maintenance, process upsets, or emergency depressurizing for safety reasons.

6.1 Pipeline Systems Flaring, Incineration, and Venting Decision Tree

Licensees must use the decision tree analysis shown in figure 7 to evaluate all new and existing pipeline systems, including compression station flares, incinerators, and vents, except for intermittent small sources (less than 100 m³ per month) such as pig trap depressurizing. These evaluations must be updated before any planned flaring, incinerating, or venting.

- 1) Licensees must document alternatives considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation.
- 2) Licensees must assess opportunities to eliminate or reduce flaring, incineration, and venting of gas due to frequent maintenance or facility outage as follows:
 - a) Investigate and correct repeat events at gas pipelines and related facilities (e.g., compressor stations).
 - b) Address public complaints and concerns about pipeline facility flaring, incineration, or venting.
 - c) Investigate and implement feasible measures to conserve gas from the depressurizing of pipeline systems.
- 3) Licensees of gas pipeline systems must ensure that flares, incinerators, and vents are designed and operated in compliance with sections 7 and 8, good engineering practices, and any other safety codes and regulations required by other agencies.
- 4) The sulphur recovery requirements of section 9 and *ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* apply to any continuous flaring or incineration of sour gas at gas gathering facilities (e.g., compressor or dehydrator sites).

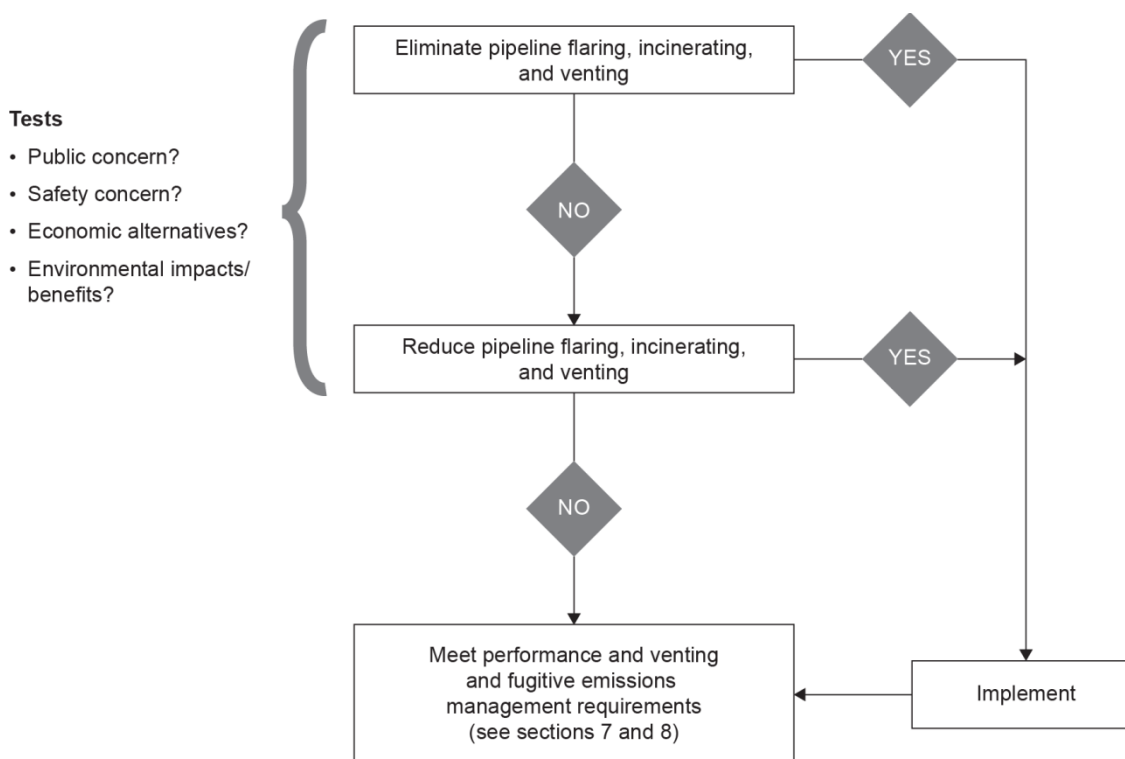


Figure 7. Pipeline flaring, incinerating, and venting decision tree (adapted from CASA)

6.2 Additional Requirements for Gas Gathering Systems

- 1) All monthly flared, incinerated, and vented volumes must be reported separately on Petrinex in accordance with section 10 and *Directive 007*. Incinerated volumes must be combined with, and reported as, flared volumes.
- 2) Gas containing more than 5 parts per million (ppm) H₂S must not be released from a pipeline without the approval of the AER unless the gas is burned such that it meets the requirements in section 7.
 - Flaring or incineration of gas must meet the requirements in section 7.
 - Venting of gas must meet the requirements in section 8.
- 3) Licensees must get an AER temporary flaring/incineration permit in order to use temporary flares or incinerators for the disposal of sour gas containing more than 50 mol/kmol (5 per cent) H₂S, as described in section 3.3.
 - a) Permits are not required for disposal of small amounts of sour gas if the requirements defined in section 3.3.2 are met.
 - b) Permit request requirements (section 3.5) apply to temporary flares and incinerators used for sour gas pipeline depressurizing, except in emergencies.
- 4) Notification requirements described in table 2 apply.

6.3 Natural Gas Transmission Systems

This directive applies to flaring, incineration, and venting in conjunction with natural gas transmission systems, subject to the following provisions:

- 1) Licensees of sweet natural gas transmission pipelines must minimize venting, flaring, and incineration volumes.
 - a) The economic evaluation in section 2.9 does not apply to evaluating conservation of gas from nonroutine pipeline depressurizing for maintenance.
 - b) When evaluating conservation of gas from planned nonroutine pipeline depressurizing, licensees must consider the value of gas, the costs of conserving the gas, and the economic effects of extending outages on downstream customers and upstream producers.
- 2) Flaring or incineration of gas from sweet natural gas transmission pipeline depressurizing may not be practical when impacts on system customers and producers are considered. In such situations, the appropriate AER field centre may allow the venting of gas to reduce the duration of system outages and related impacts.

6.4 Notification

- 1) Licensees must notify residents, schools, and the appropriate AER field centre as specified in section 3.8 and table 2 of nonroutine flaring, incineration, or venting at licensed gas pipeline facilities as follows:
 - a) If pipeline facility flaring, incineration, or venting exceeds four hours in duration or $30 \times 10^3 \text{ m}^3$, licensees must notify as specified in section 3.8 and table 2.
 - b) In areas where more stringent notification requirements than those defined in table 2 are required or through other regulatory requirements, licensees must comply with the more stringent requirements.
- 2) Licensees must provide the appropriate AER field centre with at least 24 hours' notice of planned pipeline facility outages that will result in flaring, incineration, or venting.
- 3) When nonroutine pipeline flaring, incineration, or venting is planned, licensees of sweet natural gas transmission pipelines must notify the appropriate AER field centre and discuss the measures taken to minimize emissions.
 - a) Flared and vented volumes of sweet natural gas must be reported separately. Incinerated volumes must be combined with, and reported as, flared volumes.

7 Performance Requirements

These requirements apply to flares and incinerators in all upstream oil and gas industry systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing. Flare and incinerator systems include associated separation equipment, piping, and controls.

For the purposes of this directive, the terms flare and incinerator are used interchangeably except as specifically noted in sections 2.6 (requirement 2), 7.1, 7.4, and 7.8. In these sections, some requirements are specific to the type of equipment used, and this is specified in those requirements.

All requirements in *Directive 060* that apply to incinerators apply to enclosed combustors (a type of incinerator) unless otherwise stated. To be considered an enclosed combustor, an incinerator must meet the design and operation requirements in section 7.1.3. Section 7.8 sets out reduced equipment spacing requirements specific to enclosed combustors.

Although some design or operating specifications are provided, this directive is not a substitute for comprehensive engineering design codes and guidelines. It identifies minimum AER regulatory requirements but is not intended as a comprehensive design manual.

- 1) The licensee, operator, or approval holder must ensure that a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*¹⁰ is responsible for the design or review of flare and incinerator systems, including separation, related piping, and controls, and for the specification of safe operating procedures.
 - a) Equipment and controls design information must be provided to the AER upon request if the AER determines that there is a concern with the equipment or controls.
- 2) The licensee, operator, or approval holder must ensure that operating procedures that define the operational limits of flare or incinerator systems are documented and implemented and that these procedures meet the design requirements.
 - a) Operating limits and procedures must be provided to the AER immediately upon request.
 - b) Flare and incinerator systems must be operated within the operational ranges and types of service specified by the designing or reviewing engineer, technician, or technologist. If this equipment is used for emergency shutdowns, this must be considered in the design.
- 3) If using, in a field service, a flare or incinerator that has not previously been field tested, the licensee, operator, or approval holder must be able to provide actual monitoring data to show

¹⁰ *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

that performance specifications will be met.

- a) Field testing of newly designed equipment is not allowed unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted, or unless the facility is capable of being shut in if problems arise.
- 4) *ANSI/API Standard 521: Pressure-Relieving and Depressuring Systems*, as well as applicable fire safety codes, electrical codes, CSA standards, and mechanical engineering standards, are all necessary references for the design of gas combustion systems.
- 5) The licensee, operator, or approval holder must comply with Alberta safety regulations with respect to the design of pressure vessels and piping systems and the design of equipment and operating procedures (see *Pressure Equipment Safety Regulation*).
- 6) The AER recommends that all licensees, operators, and approval holders use best engineering practices, as well as appropriate engineering codes and standards, in the design and operation of flare systems.

7.1 Conversion Efficiency

Definitions and calculations for carbon conversion efficiency, sulphur conversion efficiency, and combustion efficiency are in appendix 2.

- 1) Flares and incinerators and other gas combustion systems, including those using sour gas as a fuel for production or process equipment, must be designed, maintained, and operated so that emissions do not
 - a) result in off-lease H₂S odours, or
 - b) exceed the *AAQO*.
- 2) The licensee, operator, or approval holder must modify or replace existing flares or incinerators if operations result in off-lease odours, odour complaints, or visible emissions (e.g., black smoke).

7.1.1 Heating Value and Exit Velocity for Flares

If a flare is also subject to both an AER and an AEP approval, the more stringent requirement on minimum heating value will apply.

- 1) The combined net or lower heating value of gas, including makeup gas, directed to a flare must not be less than 20 megajoules per cubic metre (MJ/m³), except as noted below:
 - a) If existing stacks have an established history of stable operation and compliance with the *AAQO* (the licensee, operator, or approval holder is expected to support claims that existing stacks have operated satisfactorily over time), the licensee, operator, or

approval holder is allowed to maintain the current heating value provided it is not less than 12 MJ/m³.

- i) If flare stacks have a history of flame failure, odour complaints, or exceedances of the *AAQO*, the licensee, operator, or approval holder must operate with a combined flare gas heating value of not less than 20 MJ/m³.
 - b) The combined net or lower heating value of acid gas plus makeup gas directed to existing or new flares must not be less than 12 MJ/m³ under any circumstance.
 - c) Sour gas plant emergency systems must be configured to ensure that the flared gas heating value is not less than 12 MJ/m³ and that the *AAQO* are met.
 - i) The AER recommends that 20 MJ/m³ heating value be maintained for nonroutine flaring but recognizes that short-duration emergency flaring with a gas heating value of less than 20 MJ/m³ may occasionally occur.
- 2) If makeup gas is required, it must be specified for flare stacks by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.¹¹
 - a) Equipment controls must be installed, and operating procedures must be documented to ensure minimum makeup gas during routine and nonroutine operating conditions.
 - b) Facilities must be operated in compliance with specified requirements for minimum makeup gas.
- 3) The flare tip diameter must be properly sized for the anticipated flaring rates. The AERflare.xls spreadsheet provides a range of recommended values.
 - a) The AER recommends that stacks be designed to avoid downwash due to low exit velocities and excessive noise due to high exit velocities.
- 4) Equipment and controls design information must be provided to the AER upon request if the AER determines that there is a concern with the equipment or controls.
- 5) Operating limits and procedures must be provided to the AER immediately upon request.

7.1.2 Minimum Residence Time and Exit Temperature for Incinerators

If an incinerator is subject to an *EPEA* approval, any requirements regarding minimum residence time or exit temperature in that approval will take precedence over these requirements. The requirements below do not apply to sour gas plants subject to AEP approvals.

¹¹ *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

- 1) Incinerators must provide a minimum residence time¹² of 0.5 seconds at maximum flow rate or more as required for complete combustion of heavier gases.
 - a) Incinerators must be operated without exposed flame.
 - b) If the gas contains less than 10 mol/kmol (1 per cent) H₂S and the unsupplemented heating value of the gas is 20 MJ/m³ or more, no minimum residence time is required.
- 2) Incinerators must operate with a minimum exit temperature¹³ of 600°C.
 - a) For combustion of gases with less than 10 mol/kmol (1 per cent) H₂S and an unsupplemented heating value of 20 MJ/m³ or more, no minimum exit temperature or temperature monitoring is required.
 - b) For combustion of gases with more than 50 mol/kmol (5 per cent) H₂S, the facility must be designed to automatically shut down if the exit temperature of the incinerator drops below either 600°C or the required temperature to meet the *AAAQO*, whichever is higher.
 - i) The incinerator must also be equipped with process temperature control and recording.
 - ii) All violations, together with measures taken to prevent recurrence, must be immediately reported by the licensee, operator, or approval holder to the appropriate AER field centre.
- 3) Any operator proposing to use combustion technology that does not meet the above requirements (minimum exit temperature and minimum residence time) must submit third-party-verified conversion efficiency test results to the AER for approval unless the facility is subject to an *EPEA* approval.
 - a) Test programs and submissions must be provided by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*¹⁴ and must include
 - i) inlet gas parameters, including flow rates and composition;
 - ii) stack gas exit parameters, including temperature and composition;
 - iii) material and energy balance calculations;
 - iv) a mass-weighted conversion efficiency value representative of the exit conditions (see section 7.1.2[6] below);

¹² Residence time is calculated between the top of the final burner and the stack exit.

¹³ Exit temperature must be measured within one stack diameter of the exit. A shielded thermocouple must be used if the burner flame is visible to the temperature monitor. For further information, consult the *Alberta Stack Sampling Code* or contact Alberta Environment and Parks.

¹⁴ *Engineering and Geoscience Professions Act*, RSA 2000 c. E-11, as amended.

- v) discussion of the variation of measured and calculated results, depending on sampling location across the stack; and
 - vi) discussion of extending test results to other inlet conditions, including discussion of inlet limitations for H₂S concentration and inlet gas flow rate.
- b) All testing must meet the *Alberta Stack Sampling Code*.¹⁵
- c) Temperature monitoring and reporting requirements would still apply.
- 4) Equipment and controls design information must be provided to the AER upon request if the AER determines that there is a concern with the equipment or controls.
- 5) Operating limits and procedures must be provided to the AER immediately upon request.
- 6) Any licensee, operator, or approval holder using incinerators must be able to provide details about the conversion efficiency of the equipment. Any of the following are considered to be acceptable evidence of compliance with this requirement:
 - a) the design at the maximum specified capacity meets the residence time, temperature, and conversion efficiency requirements (see [6][b] below), as calculated using the AERincin.xls spreadsheet
 - b) the conversion efficiency for incinerators is 99 per cent or more, based on one of the following:
 - i) the manufacturer's third-party-verified conversion efficiency test results, provided that the tests were conducted under conditions representative of the facility design
 - ii) actual field measurements of conversion efficiency from the operating facilities following start-up (see also section 7[3]) .
 - c) If conversion efficiency is less than 99 per cent, the incinerator will be considered to operate as a flare and must meet all requirements for flares, including stack height.

7.1.3 Design and Operating Parameters for Enclosed Combustors

- 1) Enclosed combustors must be designed and operated as follows:
 - a) Combustion process must be totally enclosed, except for the combustion air intake and the exhaust discharge.
 - b) There must be no visible flame.
 - c) All surfaces exposed to the atmosphere must
 - i) operate below the temperature that would ignite a flammable substance present in the surrounding area, or

¹⁵ Copies of the *Alberta Stack Sampling Code* are available at cost from the [Queen's Printer](#).

- ii) be shielded or blanketed in such a way to prevent a flammable substance present in the surrounding area from contacting the surface.
- d) Exhaust gases must be below auto-ignition temperature of a flammable substance present in the surrounding area.
- e) All intakes must be equipped with a flame arresting device.

7.2 Smoke Emissions

- 1) Smoke emissions from a well, battery, or gas plant must be controlled in accordance with sections 7.040(1) and 9.050(6)(d) of the *OGCR*, except under emergency circumstances that involve equipment failure or as otherwise approved by the AER.
 - a) Routine gas combustion must not result in continuous or repeat black smoke emissions.
 - b) Black smoke from nonroutine or emergency flaring must not exceed an average of 40 per cent opacity over six consecutive minutes or as defined, after the issue of this directive, in Alberta's *Environmental Protection and Enhancement Act Substance Release Regulation*.¹⁶
- 2) Any smoke emissions that may result in public concern must immediately be reported to the appropriate AER field centre.

7.3 Ignition

- 1) Acid gas and sour gas flares and incinerators must have reliable systems that ensure continuous ignition of any gas that may discharge to the device.
 - a) At all facilities (excluding gas plants and batteries regulated as crude bitumen batteries) where the gas contains more than 10 mol/kmol H₂S, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., sour water or condensate tank flash-gas) and intermittent (e.g., emergency depressurizing) sources.
 - b) At crude bitumen batteries where the H₂S release rate is greater than 0.04 m³/hr, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., storage tank flash-gas) and intermittent (e.g., truck loading operations) sources.
 - c) At gas plants where gas contains more than 10 ppm H₂S, pilots and automatic ignition must be installed on flares and incinerators.
 - d) If repeat failures have occurred or off-lease odours or other impacts have resulted from failure to ensure ignition of sour gas, regardless of H₂S content, the AER may require installation of
 - i) pilots and automatic ignition, and/or

¹⁶ *Substance Release Regulation*, AR 124/93.

- ii) flame failure detection and alarms.
- 2) Manual flare and incinerator ignition subject to good fire safety practices will be accepted for nonroutine purposes where
 - a) no continuous gas flow exists, and
 - b) no automatic relieving systems are connected to the stack.

7.3.1 Requests to Extinguish Sour Flare Pilots at All Batteries

Continuous pilots may be necessary where gas is flared or incinerated on a constant or routine basis (see section 7.3) or where sour gas can potentially be released from pressure safety valves (PSVs) or emergency shutdown valves (ESDVs). In situations where gas is not continuously or routinely flared, where ESDVs are not configured to depressurize facilities to flare, and where maximum foreseeable operating pressures are well below PSV release pressures, the potential exists to safely conserve natural gas by extinguishing the flare pilots.

When considering a request to extinguish flare or incinerator pilots, the AER field centre takes into account both local conditions and the operating history of the facility.

- 1) The licensee, operator, or approval holder must get approval from the appropriate AER field centre to extinguish flare pilots at sour gas batteries.
- 2) The issuing of an approval is only considered if
 - a) the maximum design operating pressure of production piping and pressure vessel systems is greater than 105 per cent of the maximum stabilized static wellhead pressure of all wells connected to the battery;
 - b) there will be no continuous or routinely flared or incinerated gas streams;
 - c) the facility is connected to sweet or level-1 or level-2 sour wells;
 - d) no active injection or cycling schemes are taking place in or planned for any pools with wells connected to the facility;
 - e) the facility connections to the flare are isolated with rupture disks upstream of PSVs. This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association; and
 - f) all manual depressurizing valves connected to the flare system contain double block valves.
- 3) Requirements for extinguishing flare or incinerator pilots are in appendix 11.
- 4) If the licensee, operator, or approval holder proposes to connect additional wells to an existing approval, they must first supply updated information and get approval from the appropriate AER field centre.

7.4 Stack Design

Flares and incinerators must meet or exceed the following stack design requirements:

- 1) Flare and incinerator stacks must be designed so that the total radiant heat intensity at ground level will not exceed 4.73 kilowatts per square metre (kW/m²).
 - a) Ground-level radiant heat determinations for flares must be based on calculation procedures outlined in the AERflare.xls spreadsheet, *ANSI/API Standard 521* section 6.4.2.3, or *GPSA Engineering Data Book* (13th edition), section 5. Incinerators must be operated without exposed flame.
 - b) Exceptions to the requirement in section 7.4(1) will be considered on request to the AER, provided an equivalent level of safety can be ensured.
 - i) In such cases, the licensee, operator, or approval holder must restrict access to the area where the radiant heat intensity guideline could be exceeded and must ensure that this area is free of combustible materials and vegetation. Access restrictions must include appropriate warning signs, and the area must be clearly marked.
 - ii) Appropriate procedures (e.g., safe-work permit system) must be in place when it is necessary to work within the area where the radiant heat intensity guideline could be exceeded.
- 2) Flares and incinerators located within a distance of 5 times the height of any neighbouring buildings must have a height of at least 2.5 times the height of the highest building, tank, or enclosed structure on the lease site.
 - The foregoing does not apply to enclosed combustors or devices for destruction of trace vent gases, such as those emitted from gas dehydrators.
- 3) Flare stacks for acid or sour gas containing more than 10 mol/kmol H₂S must have a height of at least 12 m above ground level. At crude bitumen batteries where the H₂S release rate is greater than 0.04 m³/hr, the minimum height above ground level for the flare stack is 12 m, or such greater height as may be required to ensure that the *AAQO* are not exceeded. Existing crude bitumen batteries must meet the minimum height requirement by December 31, 2015.
- 4) Flares and incinerators must be high enough to provide adequate plume dispersion to comply with the *AAQO* for SO₂ (see section 7.12).
 - a) Proper stack heights must be used in order to minimize gas consumption. If the use of supplemental makeup gas is proposed, all other options must be investigated first. Makeup gas use and amounts must be justified.
- 5) Interconnecting lines to the flare or incinerator must be secured to prevent whipping or flailing.

7.5 Sour and Acid Gas Flaring/Incineration Procedures

A licensee, operator, or approval holder must meet the requirements in this section or those in table 1, whichever is more stringent and results in more gas being shut in.

Devices for combustion of sour or acid gas must be designed and evaluated to ensure compliance with the *AAQO* for SO₂. Evaluations must use methodologies acceptable to the AER and AEP. One of the methods described in section 7.12 or AEP's *Non-Routine Flaring Modelling Guidance* must be used.

- 1) A cumulative emissions assessment must be conducted if a flaring event is routine and if modelling results of the individual source exceed one-third of the *AAQO* for SO₂ (see section 7.12).
- 2) It is not necessary to do a cumulative emissions assessment if the routine flaring is reasonably expected to be of short duration (less than four hours). Cumulative assessment requirements are intended to address the effects of multiple or continuous SO₂ sources in a given area (see section 7.12.3). Even if a cumulative emissions assessment is not required, modelling may still be required, as described in section 7.12.
 - a) Operating procedures must be put into place to limit the release duration if the routine stack design is based on the above exception.
- 3) If operating procedures and controls are used to limit the magnitude or the duration of the event, they must be documented, and the facility must be operated in accordance with these procedures.
 - a) Automated shutdowns must be installed in facilities that are not staffed 24 hours/day (i.e., are semi-attended) to ensure compliance with this requirement.
 - b) Staff responsible for operations must be aware of the current operating procedures and must be trained at following them.
- 4) Operating procedures and related dispersion evaluations must be provided to the AER upon request.

7.6 Liquid Separation

Entrained liquids in a flare or incinerator stream may reduce combustion efficiency and contribute to increased emissions of total reduced sulphur compounds, hydrocarbons, and products of incomplete combustion. Proper gas-liquid separation facilities adequate to protect the pipeline system or gas combustion system must be used.

Note that for the purposes of this section and section 7.6.1, the terms knockout, knockout drum, scrubber, and separator are used interchangeably. The following requirements apply to all of these devices.

- 1) Liquid separation equipment must be provided in both temporary (including well test) and permanent flare and incinerator systems to prevent the carryover of liquid hydrocarbons, water, or other liquids.
- 2) Flare and incinerator separators must be designed in accordance with good engineering practice to remove droplets of 300 to 600 micron diameter and larger (see *ANSI/API Standard 521*).
 - a) Designs must be based on the lowest density hydrocarbon liquids that could be released to the flare or incinerator system.
- 3) The flare and incinerator separators or knockout drums must be designed to have sufficient holding capacity for liquid that may accumulate as a result of upstream operations, such as hydrocarbon carryover, liquid slugs, and line condensation.
- 4) All flare and incinerator separators and knockouts must have visual level indicators and operating procedures to ensure that the liquid retention in the vessel will not exceed the maximum design liquid level under all operating conditions.
 - a) For manually operated flares and incinerators (e.g., maintenance flares) where the flare or incinerator is normally isolated from the process stream (i.e., manual block valve), visual level indicators are not required when the operator has operating procedures in place to assess and mitigate the risk of liquid carryover. In the absence of an adequate operating procedure, the separator must be emptied before each flaring event.
 - i) These operating procedures must be provided to the AER immediately upon request.
- 5) All flare and incinerator separators and knockouts must have high-level facility shutdowns or high-level alarms that can be responded to by the operator before liquid carryover. If impacts such as liquid carryover or unacceptable smoke emissions (see section 7.2) have occurred as a result of failure to control liquid level, both high-level facility shutdowns and high-level alarms must be provided.
 - a) Where only manually operated flaring or incineration will occur (such as manual equipment depressurizing, handling hydrates, or for well cleanup and initial testing) and the operation is continuously attended, high-level facility shutdowns or high-level alarms are not required. Where personnel are not devoted to a flaring or incineration operation, the operation will not be considered to be continuously attended, despite a facility being continuously staffed.
- 6) High-level alarms and facility shutdowns must be installed on all flare and incinerator separators where liquid streams are directed to the separator for storage or where free liquids are contained in continuously combusted streams.

- 7) Flare and incinerator separators or knockout drums must be designed and be in accordance with AER *Directive 055: Storage Requirements for the Upstream Petroleum Industry*.
- 8) Design information on flare and incinerator system liquid separation equipment must be submitted upon request to the AER, including *Directive 056* facilities application review processes.

7.6.1 Exceptions to Separator Requirements

- 1) The AER does not require independent flare or incinerator separators in situations where the only vessels connected to the flare or incinerator are production separators equipped with a high-level shut down (HLSD) or equivalent devices or with a system that prevents liquids from entering the flare or incinerator. The following limitations apply to this exception:
 - a) The HLSD must be configured to shut down and block in, but not depressurize, the facility. The HLSD trip level must be set so that adequate vapour-liquid separation is not impaired at maximum liquid level and vapour flow rates.
 - b) If liquid carryover involving spills occurs around the flare or incinerator or if black smoke is formed, the licensee, operator, or approval holder must install adequately sized flare or incinerator separators.
- 2) The AER does not require independent flare or incinerator separators for combustion devices that destroy trace vent gases emitted from gas dehydrators.

7.7 Backflash Control

Inadequately purged flare or incinerator systems may have enough oxygen present to support combustion. Backflash may occur when the linear velocity of the combustible mixture of gas and air in the system is lower than the flame velocity.

- 1) The licensee, operator, or approval holder must take precautions to prevent backflash using appropriate engineering and operating practices, including
 - a) installing flame arresters between the point of combustion and the flare or incinerator separator, or
 - b) providing sufficient flare header sweep gas velocities (i.e., purge or blanket gas) to prevent oxygen intrusion into the flare or incinerator system.
- 2) Check valves are not an acceptable form of backflash control.
- 3) Safe-work procedures must be in place to ensure complete purging of oxygen from flare or incinerator systems before ignition.
- 4) The licensee, operator, or approval holder must provide information on backflash controls to the AER upon request if the AER determines that there is a concern with the equipment or controls.

7.8 Flare and Incinerator Spacing Requirements

Licensees, operators, and approval holders must follow good engineering and safety practices in the layout of facilities. Despite liquid separation requirements, unexpected liquid carryover to flares and incinerators can happen. Adequate spacing of these devices from areas frequented by workers and from sources of combustible gas is prudent. A licensee, operator, or approval holder must consult fire protection codes and guidelines as part of facility design. Licensees, operators and approval holders must immediately report fires (both on and off lease) caused by flares or incinerators to the local field centre.

- 1) Flares and incinerators other than enclosed combustors must be located, as measured from the base of the stack, at least
 - a) 50 m from wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours;
 - b) 50 m from storage tanks containing flammable liquids or flammable vapours;
 - c) 25 m from any oil and gas processing equipment. This does not apply to combustion devices that destroy trace vent gases, such as those emitted from gas dehydrators. These devices must be designed to prevent ignition of gas that may leak from surrounding equipment (e.g., combustion devices could be equipped with flame arresters); and
 - d) 25 m from crude bitumen wells, storage tanks, or other sources of ignitable vapour, including lined earth excavations used to store waste oil at batteries regulated as bitumen sites.
- 2) Enclosed combustors, as measured from the base, must be located at least 10 m from
 - a) wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours;
 - b) storage tanks containing flammable liquids or flammable vapours;
 - c) oil and gas processing equipment; and
 - d) other sources of ignitable vapours.

Flare knockout drums and integral knockout drums are exempt from flare and incinerator spacing requirements provided they have no means to vent to the atmosphere.

The incinerator that combusts gas from the sulphur recovery process is not required to meet incinerator spacing requirements for sulphur plant process equipment (i.e., converters and condensers).

- 3) Flares and incinerators must be located, designed, and operated so that they are not a hazard to public property. They must be at least 100 m away from surface improvements and

surface developments as defined in *Directive 056* (except for surveyed roadways or road allowances, which must be 40 m from flares and incinerators).¹⁷

- 4) The area around flares and incinerators must be free of fire hazards. Flare or incinerator spacing and operating practices must comply with the *Forest and Prairie Protection Act*¹⁸ and any regulations under that act.¹⁹
- 5) The licensee, operator, or approval holder also comply with the *Forest and Prairie Protection Regulations*, Part I (AR 135/72), in unforested areas where there is a fire hazard associated with flare and incinerator operations.
- 6) In certain circumstances, the AER may consider variances to AER flare and incinerator spacing requirements.
 - a) The AER discourages variance requests for new facilities.
 - b) Existing well site equipment spacing waivers are maintained.
 - c) A licensee, operator, or approval holder requesting a spacing variance must first consult relevant codes and engineering practices and provide related information in support of the variance request.

7.9 Compliance with Fire Bans

Information on fire bans issued by AEP can be found at www.albertafirebans.ca, directly from local municipal districts, or by calling 1-866-310-FIRE (3473).

7.10 Noise

- 1) Flares and incinerators must be designed and operate in compliance with *Directive 038*.

7.11 Flare Pits

Flare pits must not be used at any facilities built after July 1, 1996. For facilities built before July 1996, the licensee, operator, or approval holder must meet the following requirements:

- 1) All existing flare pits must be decommissioned by December 31, 2015. Exemption requests for cryogenic flare pits must be submitted to the AER by December 31, 2015.
- 2) Produced liquids must not enter the pit, in accordance with section 8.080 of the *OGCR*.
- 3) Flaring of sour gas must comply with the *AAQO*.
- 4) Gas containing more than 10 mol/kmol H₂S must not be flared in pits.

¹⁷ The 40 m spacing requirement applies to public road allowances and roads to which the public has open access. There is no spacing requirement for private licensee access roadways or private roadways on operating sites.

¹⁸ *Forest and Prairie Protection Act*, RSA 2000, c. F-19, as amended.

¹⁹ As at the date of this directive, *The Forest and Prairie Protection Regulations*, AR 135/72.

- 5) The licensee, operator, or approval holder must conduct evaluations of solution gas flares for flare pits as described in sections 2.3 and 2.9 and implement the resulting decision.
- 6) Access restrictions and procedures must be in place in areas around flare pits where ground-level radiant heat intensity at maximum flare rates will exceed 4.73 kW/m².
- 7) If the facility is modified or if the facility increases its average annual production, the flare pit must be replaced with a flare stack.
- 8) The AER can require the licensee, operator, or approval holder to replace flare pits with flares systems if any part of the facility is in noncompliance.
- 9) Operation of flare pits must comply with the provisions of the *Forest and Prairie Protection Act*²⁰ and with any regulations under that act.²¹

7.12 Dispersion Modelling Requirements for Sour and Acid Gas Combustion

The following requirements apply to the combustion of sour gas in process equipment, such as steam generators and process heaters, as well as to flares and incinerators.

- 1) The licensee, operator, or approval holder must demonstrate, using dispersion modelling methods outlined in AEP's *Air Quality Model Guideline*, that SO₂ and H₂S emissions from the burning of sour and acid gas will not result in exceedance of the *AAQO* if the gas contains the following amounts or more:
 - 10 mol/kmol H₂S, or
 - one tonne/day of sulphur emission rate during the event.

A licensee, operator, or approval holder combusting gas below these concentrations and emission rates is encouraged to consider dispersion modelling as part of environmental considerations. Facilities requiring approval from AEP under the *EPEA* may need more detailed evaluation. A licensee, operator, or approval holder should consult AEP directly in these instances.

- 2) Dispersion modelling must be done by qualified technical personnel using computer models and methodologies acceptable to AEP or, if appropriate, the method described in section 7.12 and appendix 7.

²⁰ *Forest and Prairie Protection Act*, RSA 2000, c. F-19, as amended.

²¹ As at the date of this directive, *The Forest and Prairie Protection Regulations*, AR 135/72.

7.12.1 Modelling Approach

The definitions of screening and refined dispersion modelling assessments are in appendix 8.

- 1) The licensee, operator, or approval holder must
 - select an appropriate model,
 - be able to demonstrate that the model selected is appropriate and follows AEP accepted methodologies and standards, and
 - use representative input parameters (e.g., flow rate, gas composition) within the model and be prepared to demonstrate that those parameters are representative.

7.12.2 Individual Source

- 1) Initial modelling may be conducted using the screening assessment provided in the AERflare.xls and AERincin.xls spreadsheets.
- 2) For a screening assessment, ambient air quality modelling must use
 - a) stack-specific terrain extracted by the spreadsheets or from 1:50 000 topographical National Topographic System (NTS) maps,
 - b) the point source (not flare) option,
 - c) full screening meteorology,
 - d) appropriate land use characteristics, and
 - e) emission parameters as calculated by the AERflare.xls and AERincin.xls spreadsheets (e.g., velocity, diameter, and temperature inputs for dispersion modelling).
- 3) Modelling must address a full range of expected flow-rate conditions and may include the low, average, and maximum flow rate.
- 4) The selected flare or incinerator design must not result in ground-level SO₂ concentrations higher than those in the *AAQO*.
 - a) A refined assessment may be used if the screening assessment results in an impractical stack height.
 - b) If it is not practical to design flares or incinerators of sufficient height for adequate dispersion, the licensee, operator, or approval holder may consider
 - i) using an air quality management plan (see appendix 7),
 - ii) operating procedures and process controls to prevent emission rates or durations that would exceed the *AAQO* (see sections 7.5, 7.12.4), and
 - iii) adding gas to increase heat release and plume rise. As stated in section 7.4, proper flare stack height must be used to minimize gas consumption.

- c) The risk-based criteria discussed in section 7.12.4 do not apply to continuous (nontemporary) sour gas combustion at permanent facilities.

7.12.3 SO₂ Cumulative Emissions Assessment

If predicted maximum hourly average ground-level concentrations for the individual continuous source are more than one-third of the *AAQO* for SO₂, then the licensee, operator, or approval holder must conduct an assessment of cumulative effects of all routine SO₂ sources.

- 1) The following steps must be followed for cumulative emissions assessments:
 - a) Identify the farthest downwind location where predictions exceed one-third of the hourly average *AAQO* for SO₂ to define the radius of influence.
 - b) Identify all other continuous sources of SO₂ within this radius of influence up to a maximum of 20 km; if no other sources of SO₂ are within the radius, no further modelling is required.
 - c) Quantify SO₂ emissions from these other sources and obtain all necessary input data, such as stack height and other parameters (the licensee, operator, and approval holder must share related data with each other on a timely basis). Maximum hourly flow-rate conditions must be used for all sources in the radius of influence.
 - i) In applications for a continuous source, other sources must be modelled at licensed emission rates.
 - ii) SO₂ cumulative assessments are not required for nonroutine flaring, venting, and incineration (e.g., well test or planned maintenance blowdown).
 - d) Model the cumulative effects of the SO₂ emission sources.
 - e) If the sum exceeds the *AAQO*, determine the appropriate stack height required to meet the *AAQO*. All refined modelling must follow the methods outlined in the *Air Quality Model Guideline* (2013).

7.12.4 Temporary and Well Test Flaring Dispersion Modelling

This section applies to temporary events that may require a permit (as described in section 3) and well test flaring or incineration activities. These activities include well testing, well cleanup, well servicing, coalbed methane well testing, underbalanced drilling, and sour gas pipeline (as defined in *Directive 056*) blowdown through temporary flare or incinerator equipment. These activities exclude nonroutine flaring or incineration at permanent AER-licensed facilities.

- 1) The licensee, operator, or approval holder must complete either the flaring (AERflare.xls) or incinerator (AERincin.xls) spreadsheet.
- 2) Information on ambient air quality impact evaluations must be included in requests to burn sour gas or, if no permit is required, must be provided to the AER upon request. The

dispersion modelling within AERflare.xls or AERincin.xls may be sufficient if a screening assessment is adequate.

- 3) Sour gas flares and incinerators must be designed for the gas composition and flow rates of the situation for which there is a temporary permit (see section 7 for further information).
- 4) Equipment design or the operating procedures, or both, must address all modelled predictions that exceed the *Alberta Ambient Air Quality Objectives*, excluding predicted values that meet the risk-based criteria. The risk-based criteria only apply to temporary events.
 - a) Risk-based criteria for temporary events allow limited exclusion of predicted ambient air quality results, provided that
 - i) the 99th percentile predicted values at a receptor do not exceed the one-hour SO₂ Alberta ambient air quality objective, and
 - ii) the 99.9th percentile predicted values do not exceed a predicted one-hour SO₂ ambient concentration of 900 micrograms (µg) per m³.

Note that whereas model predictions up to 900 µg/m³ will be considered, actual exceedances of the *Alberta Ambient Air Quality Objectives* are never permitted.
 - b) Risk-based criteria are incorporated into the flare and incinerator spreadsheets for screening modelling.
 - c) If refined modelling is required to determine whether the temporary event meets the risk-based criteria, the refined modelling input files from the spreadsheet must be used.
 - d) The AER will also consider use of the risk-based criteria in situations where air quality management plans (see appendix 7) are necessary to ensure compliance with the *Alberta Ambient Air Quality Objectives*.
 - i) Air quality management plan decision criteria may be based on meteorological or ambient air quality monitoring data.
- 5) Concurrent temporary sour gas burning (i.e., multiple well test flaring/incinerating) must not occur within 20 km of each other unless a licensee can demonstrate that the cumulative emissions from flaring can meet the *AAAQO*.
- 6) Licensees must retain, for one year after the flaring/incineration event, information on dispersion assessments for flares or incinerators that require dispersion modelling but do not require a flaring permit (see section 3.3.2). This information must be provided to the AER upon request.

7.12.5 Nonroutine Flaring and Dispersion Modelling

This section applies to nonroutine planned and unplanned flaring from permanent flares. Temporary and well testing activities described in section 7.12.4 are not included here.

“Nonroutine flaring” applies to intermittent and infrequent flaring and incineration. There are two types of nonroutine flaring: planned flaring and unplanned flaring.

- **Planned flaring**—Flare events where the operator has control over when flaring will occur, how long it will occur and the flow rates. Planned flaring results from the intentional depressurization of processing equipment or piping systems. Examples of planned flaring include pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests. Note that well testing dispersion modelling criteria are addressed in section 7.12.4.
- **Unplanned flaring**—Emergency or upset operational activities closely associated with facility health and safety. Flare events where the operator has no control of when flaring will occur. There are two types of unplanned flaring upset flaring and emergency flaring.
 - **Upset flaring** occurs when one or more process parameters fall outside the allowable operating or design limits and flaring is required to aid in bringing the production back under control. Examples of upset flaring include: off-spec product, hydrates, loss of electrical power, process upset, and operation error.
 - **Emergency flaring** occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of upset flaring include PSV overpressure and emergency shutdown.

Figure 8 summarizes the process for managing the nonroutine flaring of sour gas.

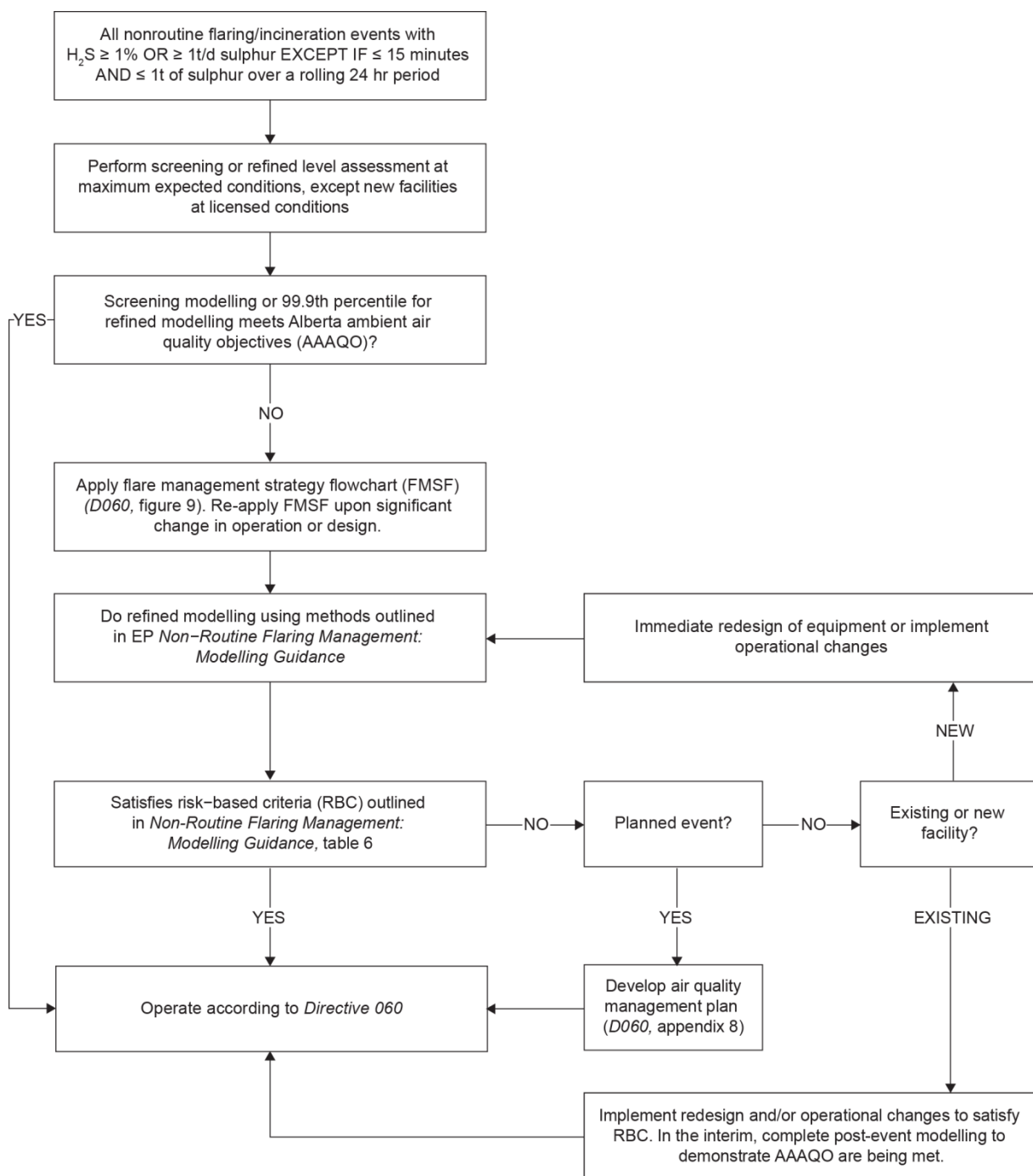


Figure 8. Comprehensive management of the nonroutine flaring of sour gas

- 1) The licensee, operator, or approval holder must evaluate impacts of nonroutine sour gas flaring on ambient air quality if
 - a) it is proposed to burn sour gas containing 10 mol/kmol H₂S (1 per cent H₂S) or more, or
 - b) 1 tonne of sulphur mass is released during the event or the day (for multiple releases).

Single nonroutine flare events that are predicted to be less than or equal to 15 minutes in duration and predicted to emit less than 1 tonne of sulphur over a rolling 24-hour period are exempt from modelling requirements.

- 2) Unless the AER requires otherwise, where previous modelling reports of nonroutine flare events show compliance with the *AAAQO* using tools and methods no longer accepted by AEP (e.g., SCREEN3, RTDM, ISC3, AQMG, and AER low risk criteria), the facility can continue to operate as is. If any emission changes occur at the respective facility or if the AER requests that new dispersion modelling be conducted for any reason, the operator will apply the flare management strategy flowchart (figure 9) and will reassess dispersion modelling using current modelling methodology and tools.
- 3) For permanent flare stacks the licensee, operator, or approval holder must assess nonroutine flaring dispersion modelling criteria where facilities lack evidence of dispersion modelling or where facilities are unable to satisfy the *AAAQO* for nonroutine flaring events using tools and methods no longer accepted by AEP:
 - a) If emissions change at existing AER-licensed facilities, the licensee, operator, or approval holder must reassess nonroutine flaring dispersion modelling criteria when a renewal or amendment is required.
 - b) All processing facilities subject to the *Environmental Protection Enhancement Act – Activities Designation Regulation* must remodel upon renewal.
- 4) Initial screen modelling may be conducted using AERflare or AERincin or dispersion modelling methods outlined in AEP's *Air Quality Model Guideline*. If nonroutine refined modelling is required or if stack design is impractical, the licensee must apply the flare management strategy flowchart (figure 9) or equivalent, and dispersion modelling evaluations must be conducted using methodologies described in AEP's *Non-Routine Flaring Modelling Guidance*. The flare management strategy flowchart and refined modelling must be reapplied if facility operation or design changes significantly.
- 5) If modelling of worst-case scenarios shows that the predicted 99.9th percentile hourly concentrations are lower than the AER SO₂ evacuation criteria from *Directive 071* and the predicted 90th percentile hourly concentration is higher than the *AAAQO* for SO₂, then for each unplanned flaring event at the facility, the licensee, operator, or approval holder must do post-event dispersion modelling. (See section 7.12.5[9]).
- 6) For planned flaring events, the licensee, operator, or approval holder must develop flare management plans that meet the risk-based criteria to ensure that the *AAAQO* are not exceeded, and implement them during flaring. It is acceptable for modelling to be based on actual flows and gas compositions, not licensed values.

- 7) If refined modelling for nonroutine flaring is required, the licensee must not exceed the risk-based criteria maximum number of flaring hours per calendar year described in AEP's *Non-Routine Flaring Modelling Guidance* table 1. The licensee, operator, or approval holder must log all flaring events, including flare duration, volume, and rates.
- 8) If nonroutine flaring exceeds the risk-based criteria maximum number of flaring hours per year described in AEP's *Non-Routine Flaring Modelling Guidance* table 1 or if the event results in an exceedance of the *Alberta Ambient Air Quality Objectives* for SO₂, the licensee, operator, or approval holder must conduct post-event dispersion modelling (see section 7.12.5[9]) and contact the AER immediately.
- 9) If post-event modelling is required, the actual conditions must be used. If site-specific meteorological data during the event is not available, five years of meteorological data from a standard period is recommended using the AEP data set (www.albertamm5data.com/). One month per year must be modelled from the data set, centred around the month of the event.
- 10) If the AER determines that the dispersion modelling has not been completed in accordance with *Directive 060* requirements, the licensee, operator, or approval holder may be subject to a regulatory response.
- 11) The licensee, operator, or approval holder is not required to provide copies of nonroutine dispersion modelling or a flare management strategy flowchart to the AER unless requested. Upon request, the licensee, operator, or approval holder must provide the evaluation to the AER within five working days.

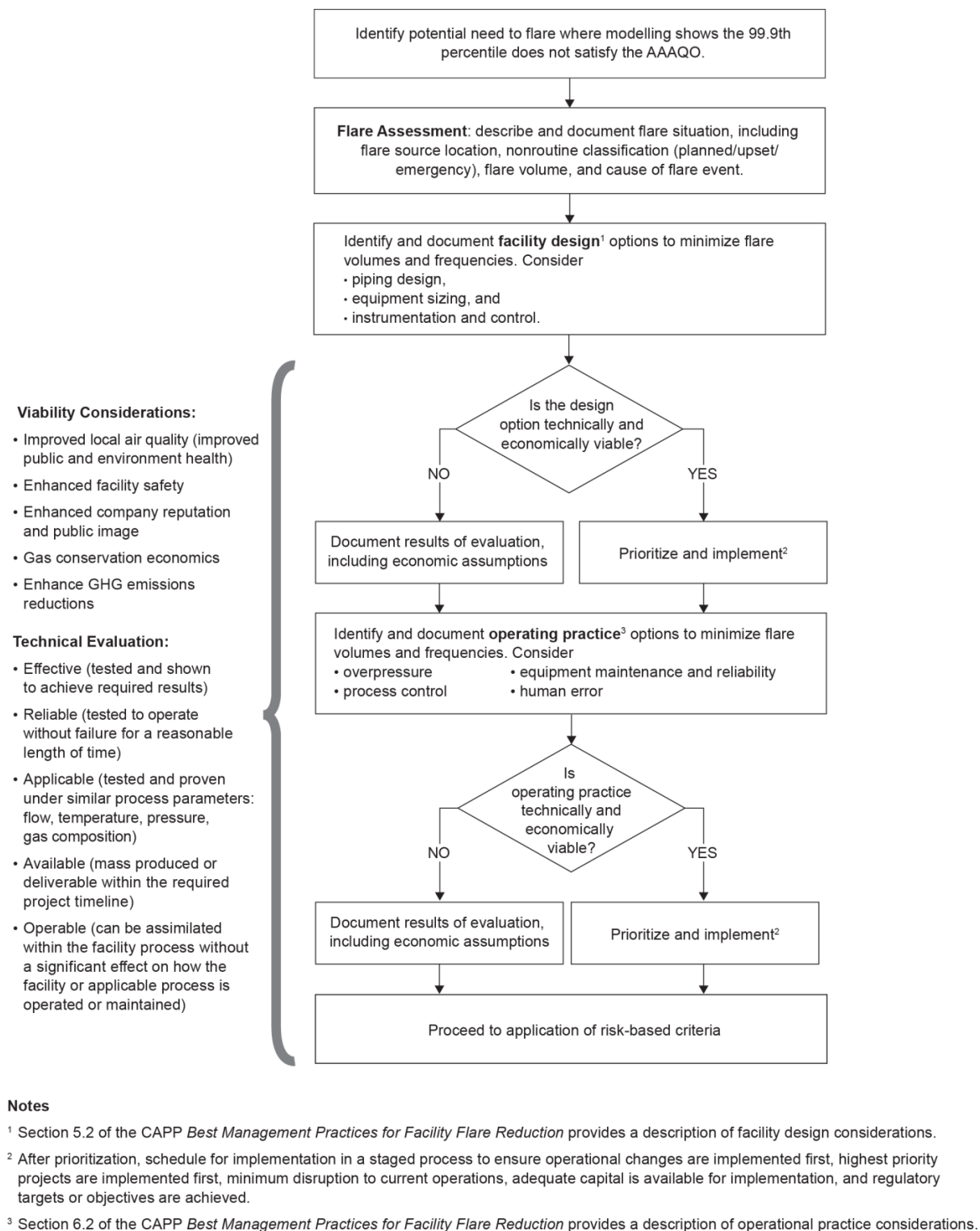


Figure 9. Flare management strategy flowchart

8 Vent Gas Limits and Fugitive Emissions Management

Vent gas and fugitive emissions are sources of methane emissions in the province. This section includes requirements to meet the target set by the Government of Alberta to reduce methane emissions from the provincial upstream oil and gas sector 45 per cent by 2025 from 2014 levels.

In this section, depending on the context, “duty holder” means the holder of an approval under the *Oil Sands Conservation Act*, the holder of a licence or approval under the *Pipeline Act* or *Oil and Gas Conservation Act*, or the operator of a facility where a licence or approval is not required under the *Oil and Gas Conservation Act*.

Figure 10 illustrates how the methane emission sources subject to the requirements in this section have been categorized.

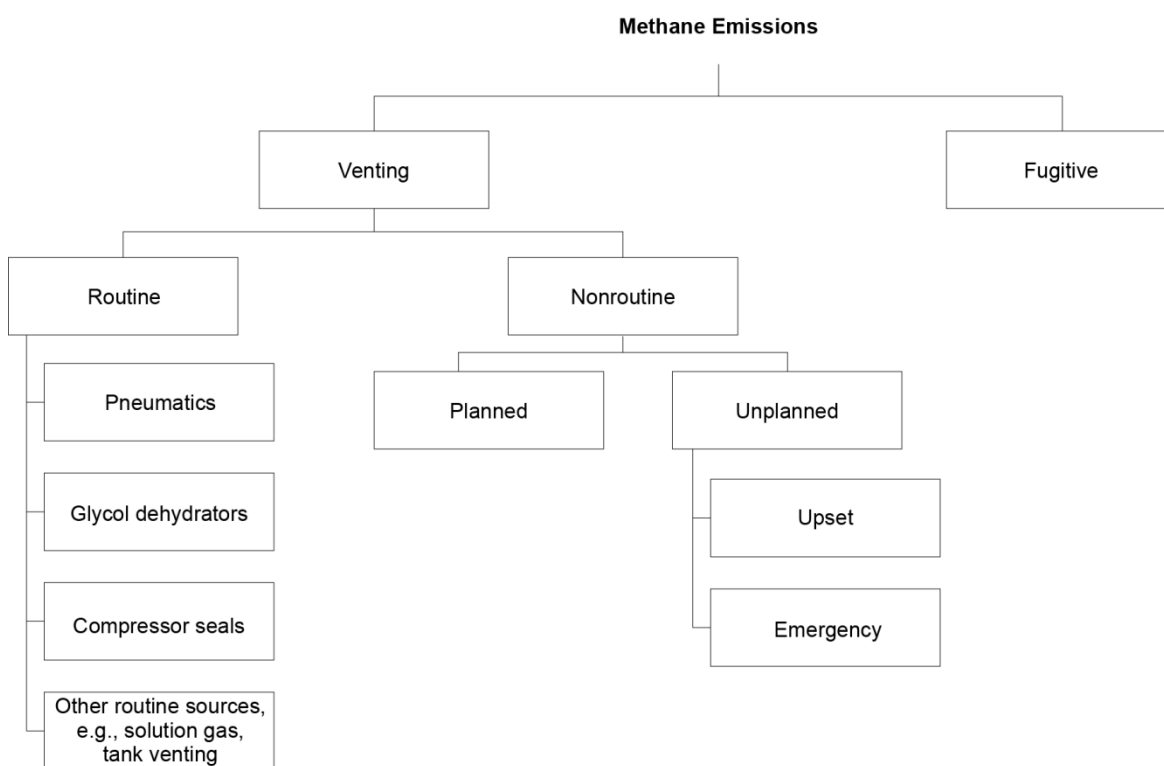


Figure 10. Methane emission sources covered under section 8

Routine venting is continuous or intermittent venting on a regular basis as part of normal operations. The AER recommends that duty holders eliminate all routine venting.

Nonroutine venting is intermittent and infrequent venting and can be planned or unplanned.

Fugitive emissions are the unintentional releases of hydrocarbons to the atmosphere.

For facilities operating under an *EPEA* approval or existing AER licence, the requirements in this section are in addition to any conditions in the *EPEA* approval or AER licence.

Unless otherwise stated, for operations in the Peace River area, requirements in this section are in addition to those set out in *Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area*.

8.1 Methane Reduction Retrofit Compliance Plan

Since the equipment retrofit and replacement requirements in section 8 may involve advance planning and investment by duty holders to ensure compliance on the date the requirements take effect, the AER will require duty holders to prepare a methane reduction retrofit compliance plan (MRRCP).

- 1) The duty holder must document an MRRCP that indicates how compliance with section 8.6 will be achieved.
- 2) The MRRCP must contain, at a minimum, the schedule to replace or retrofit existing equipment and the resources and budget allocated to ensure compliance with the requirements in section 8.6.
- 3) The MRRCP must be updated annually until January 1, 2023, to reflect material changes or progress made over the year according to the process in figure 11.
- 4) An executive of the duty holder must approve the MRRCP in writing, attesting that the MRRCP is designed to ensure compliance with the requirements in section 8.6.

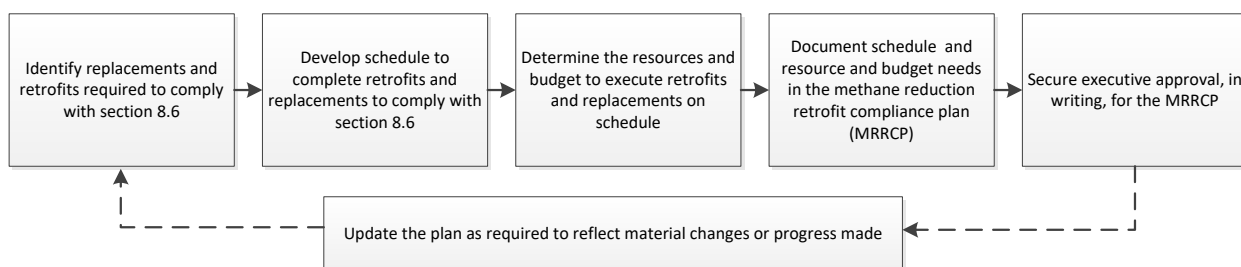


Figure 11. Process for developing and implementing a methane reduction retrofit compliance plan

8.2 Measurement and Reporting of Methane Emissions

Methane emissions may be quantified using continuous metering, periodic testing, or estimates based on accepted engineering practices. *Directive 017* identifies when vent gas from a site must be quantified using continuous metering or periodic testing, as well as acceptable testing methods. *Manual 015: Estimating Methane Emissions* provides guidance on how to estimate vent gas and fugitive emissions.

The annual methane emissions reporting period is the calendar year. The operator of record of a facility on December 31 is responsible for reporting over the entire reporting period, regardless of any changes in ownership during the reporting period.

Additional annual methane emission report requirements are set out in the corresponding vent gas limits and fugitive emissions management sections.

- 1) The operator of record for a facility that was active in a reporting period must electronically submit an annual methane emissions report to the AER by June 1 of the following calendar year or the next business day if the first is not a business day, or as otherwise directed by the AER. The first reporting period is 2019, and the first annual methane emissions report must be submitted to the AER by June 1, 2020.
- 2) Annual inventories must reflect equipment in place at the end of each reporting period.
- 3) For facilities that do not require a licence (such as small booster compressors), the venting and equipment must be reported to the nearest upstream reporting well, battery, or pipeline facility.

8.3 Overall Vent Gas Limit

Overall vent gas (OVG) is all routine and nonroutine vent gas.

- 1) The duty holder must limit OVG at a site to less than $15.0 \times 10^3 \text{ m}^3$ of vent gas per month or $9.0 \times 10^3 \text{ kg}$ of methane per month.

In addition to complying with the OVG limit, the duty holder must comply with the vent gas limits in sections 8.4 to 8.9.

8.3.1 Exceptions

Vent gas from pneumatic devices, compressor seals, and glycol dehydrators are excluded from the OVG limit until January 1, 2023. Noncombustible gas, as described in section 8.9, is excluded from the OVG limit.

8.4 Defined Vent Gas Limit

Defined vent gas (DVG) is vent gas from routine venting, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators.

- 1) The duty holder must design and operate any site with first receipt or production on or after January 1, 2022, to limit the DVG emitted to less than $3.0 \times 10^3 \text{ m}^3$ of vent gas per month per site or less than $1.8 \times 10^3 \text{ kg}$ of methane per month per site.

8.4.1 Reporting

- 1) The operator of record must include in the annual methane emissions report
 - a) the annual volume of DVG emitted (m^3) by facility ID, and
 - b) the corresponding mass of methane emitted (kg) by facility ID.

8.4.2 Exceptions

If the duty holder has opted to use the average vent gas rate for the crude bitumen fleet, as defined in requirement 8.5(1)(b), the methane emitted from the crude bitumen batteries is excluded from the DVG limit. Noncombustible gas, as described in section 8.9, is excluded from the DVG limit.

8.5 Vent Gas Limits for Crude Bitumen Batteries

This section applies to vent gas from crude bitumen batteries. Excluded from the vent gas limits for crude bitumen batteries are thermal in situ schemes and thermal in situ operations under *OSCA* and the *Oil Sands Conservation Rule*. Also excluded are batteries with either crude oil wells or crude bitumen wells that are within the Peace River area, as defined in *Directive 084*.

- 1) Effective January 1, 2022, the duty holder must limit vent gas to one of the following:
 - a) From each site, to the DVG limit prescribed in section 8.4.
 - b) From the crude bitumen fleet, to less than an average vent gas rate in each month of $1.5 \times 10^3 \text{ m}^3$ per facility ID.

The crude bitumen fleet in each month consists of facilities with non-zero production or vent volumes reported to facility IDs

- with subtype codes 331, 341, and 342; or
- with subtype codes 311, 321, and 322 that have at least one production string that
 - is reporting oil production from a pool with an assigned density greater than or equal to 920 kg/m^3 at 15°C , or
 - has a well fluid status of bitumen.

Manual 011: How to Submit Volumetric Data to the AER defines the subtype codes.

The average vent gas rate in each month is calculated as follows:

$$\frac{\text{Sum of the vent volumes from the crude bitumen fleet}}{\text{Total number of facility IDs within the crude bitumen fleet}}$$

8.6 Equipment-Specific Vent Gas Limits

8.6.1 Vent Gas Limits for Pneumatic Devices

The requirements in this section apply to gas-driven pneumatic devices, including pneumatic instruments (e.g., controllers, switches, transducers and positioners) and pneumatic pumps.

- 1) The duty holder must prevent or control vent gas from pneumatic instruments installed on or after January 1, 2022.

- 2) The duty holder must ensure that pneumatic pumps installed on or after January 1, 2022, that operate more than 750 hours per calendar year do not emit vent gas.
- 3) Effective January 1, 2023, for level controllers that emit vent gas and are installed before January 1, 2022, the duty holder must
 - a) prevent or control vent gas, or
 - b) evaluate the actuation frequency during normal operating conditions and for level controllers that actuate between 0 and 15 minutes, use a relay that has been designed to reduce or minimize transient or dynamic venting or adjust the actuation frequency to ensure that the time between actuations is greater than 15 minutes.
- 4) Effective January 1, 2023, for pneumatic instruments other than level controllers that emit vent gas and are installed before January 1, 2022, the duty holder must
 - a) prevent or control vent gas, or
 - b) ensure that the instruments have a manufacturer-specified steady-state vent gas rate of less than 0.17 m³/hr.

8.6.1.1 Exceptions

If a duty holder can demonstrate that a pneumatic instrument that vents gas is needed to maintain safe operating conditions or to achieve a necessary response time and that there is no other way of accomplishing this while still meeting venting requirement 1, 3, or 4 under section 8.6.1, then that instrument is exempted from the applicable requirement.

- 1) The duty holder must identify these exempt instruments with a weatherproof, readily visible tag.

8.6.1.2 Reporting

- 1) The operator of record must include in the annual methane emissions report the volumes from pneumatic instruments and pumps, by facility ID, of
 - a) vent gas emitted (m³), and
 - b) corresponding mass of methane emitted (kg).

8.6.2 Vent Gas Limits for Compressor Seals

The vent gas limits in this section apply to vent gas from the seals of a reciprocating or centrifugal compressor that is rated 75 kW or more and is pressurized for at least 450 hours per calendar year.

8.6.2.1 Compressor Seal Testing

- 1) For any compressor seal that emits vent gas, the duty holder must test the seal at least every 9000 hours that it is pressurized.

- 2) The test must
 - a) have a maximum single point uncertainty of ± 10 per cent for a vent rate greater than $0.10 \text{ m}^3/\text{hr}$;
 - b) have a maximum total back pressure of less than 1 kPa (includes the back pressure from the measurement device, piping, valving, and fittings) for a vent rate less than $1 \text{ m}^3/\text{hr}$;
 - c) include all vents from the compressor seal;
 - i) for reciprocating compressors, this includes piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) and compressor crankcase vent;
 - d) include all compressor seals that emit vent gas (either by testing at a single common vent terminus point or at each vent of a compressor seal); and
 - e) be conducted within 10 per cent of the average revolutions per minute and discharge pressure of the compressor. The average is to be based on the 168 pressurized hours prior to testing.
- 3) The duty holder must ensure that the testing point for each compressor seal that emits vent gas is accessible and clearly identified.

If a compressor seal has been replaced since the last test, it does not need to be retested until the next annual test.

Exception: Reciprocating compressors with piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) that are connected to control do not have to be tested annually. In these cases, gas emitted out of the compressor crankcase is a fugitive emission and subject to section 8.10.

8.6.2.2 Reciprocating Compressor Seals

A reciprocating compressor seal (RCS) includes the piston-rod-packing vents and drains and distance-piece vents and drains (including purge-system vents) on an individual throw. The reciprocating compressor crankcase vent is not subject to control requirements. Gas emitted from the crankcase of a controlled reciprocating compressor is a fugitive emission and subject to section 8.10. For uncontrolled reciprocating compressors, any gas emitted from the crankcase is vent gas from an RCS.

- 1) The duty holder must control vent gas from any seal on a reciprocating compressor installed on or after January 1, 2022, with four or more throws.
- 2) Effective January 1, 2022, the duty holder must limit vent gas from the RCS fleet to less than $0.35 \text{ m}^3/\text{hr/throw}$.

The RCS fleet consists of the duty holder's reciprocating compressors that are rated 75 kW or more, pressurized for more than 450 hours per calendar year, and either

- a) were installed before January 1, 2022, or
- b) were installed on or after January 1, 2022, and have fewer than four throws.

The vent gas from the RCS fleet is calculated as follows:

$$\frac{\sum_{i=1}^n v_i}{\sum_{i=1}^n (t_i \times c_i)}$$

where

- n = total number of reciprocating compressors in the fleet
- v = vent gas volume for the calendar year for the reciprocating compressor (m³)
- t = the number of hours per calendar year that the reciprocating compressor is pressurized
- c = number of pressurized throws for the reciprocating compressor

- 3) Effective January 1, 2022, the duty holder must bring any RCS with a measured vent gas rate greater than 5.00 m³/hr/throw to below 5.00 m³/hr/throw within 30 days of the measurement date.

8.6.2.3 Centrifugal Compressor Seals

- 1) For centrifugal compressors installed on or after January 1, 2022, the duty holder must limit the vent gas rate to less than 3.40 m³/hr/compressor. If the measured rate is not below this limit, the duty holder must take action to bring the rate below 3.40 m³/hr/compressor within 90 days of the measurement date.
- 2) Effective January 1, 2022, for centrifugal compressors installed before January 1, 2022, the duty holder must limit the vent gas rate to less than 10.20 m³/hr/compressor. If the measured rate is not below this limit, the duty holder must take action to bring the rate below 10.20 m³/hr/compressor within 90 days of the measurement date.

8.6.2.3.1 Exceptions

Vent gas from engine or turbine starts and compressor blowdowns is managed under the OVG limit in section 8.3 and excluded from the requirements in section 8.6.2.

8.6.2.4 Reporting

- 1) The operator of record must include in the annual methane emission report
 - a) the volume of vent gas emitted (m^3) from all compressor seals (including seals in compressors rated less than 75 kW and compressors pressurized for less than 450 hr/yr) by facility ID;
 - b) the corresponding mass of methane emitted (kg) by facility ID;
 - c) for each reciprocating or centrifugal compressor rated at least 75 kW and pressurized for more than 450 hr/yr, the following:
 - i) compressor frame serial number or other unique identifier,
 - ii) legal survey location (LSD-SC-TWP-RGWM),
 - iii) authorization number and name of duty holder,
 - iv) whether the equipment was installed before January 1, 2022, or on or after January 1, 2022,
 - v) compressor type (reciprocating or centrifugal),
 - vi) number of throws (if reciprocating),
 - vii) seal type (dry or wet if centrifugal),
 - viii) whether the piston-rod-packing vents and drains and distance-piece vents and drains are controlled,
 - ix) annual vent gas volume (m^3), and
 - x) annual pressurized time of compressor (hours).
- 4) The operator of record must base reported compressor seal vent gas volumes on
 - a) a test result (may include metering), or
 - b) an estimate based on accepted engineering practices.

When the compressor seal vent is tested, the test result is used to estimate the compressor seal vent gas volume for the period until the next test is conducted. If any seals are replaced between tests, an estimate based on accepted engineering practices can be used to estimate the compressor seal vent gas volume for the period from the seal replacement until the next test is done. For further guidance, see *Manual 015*.

8.6.3 Vent Gas Limits for Glycol Dehydrators

- 1) The duty holder must limit methane emissions from each glycol dehydrator installed or relocated on or after January 1, 2022, to less than 68 kg of methane/day.

- 2) Effective January 1, 2022, the duty holder must limit methane emissions from each glycol dehydrator installed or relocated before January 1, 2022, to less than 109 kg of methane/day.

8.6.3.1 Exceptions

Vent gas from glycol regenerators used in refrigeration processes is managed under the OVG limit in section 8.3 and excluded from the requirements in section 8.6.3.

8.6.3.2 Reporting

Refer to *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* for inventory requirements for active glycol dehydrators.

8.7 Additional Requirements

- 1) Provided that all other requirements in section 8 of this directive are met, section 8.031 of the *OGCR* permits the connection of pressure-relieving devices at oil production batteries to open tanks (i.e., “pop tanks”).
- 2) Hydrocarbon products stored in atmospheric storage tanks at gas plants, compressor stations, and gas batteries must not have a true vapour pressure of more than 83 kilopascals (kPa) at 21.1°C if the tanks are vented to the atmosphere.
- 3) Unless directed by the AER to flare, incinerate, or conserve all casing gas and tank-top gas, temporary, short-term venting is allowed at wells (e.g., for well unloading and liquid cleanup), facilities, batteries where conservation is in place (see partial equipment outages in table 1), and pipelines (for natural gas transmission systems, see section 6.3), with the following conditions:
 - a) Gas must contain less than 10 mol/kmol H₂S and must not result in exceedances of the *AAQO* outside the lease boundary.
 - b) Gas must not contain any free hydrocarbon liquid (if free hydrocarbon liquids are present in the produced gas, a flare [or other gas combustion device] and liquid separation must be used).
 - c) All liquids must be separated and contained in accordance with the storage requirements of *Directive 055*.
 - d) Total gas volume must not exceed 2.0 10³ m³ and the duration must not exceed 24 hours.
 - e) The duty holder must conduct notification in accordance with section 3.8 and table 2.

- f) The AER field centre may consider alternatives to these requirements should special circumstances warrant. The licensee, operator, or approval holder must contact the appropriate AER field centre for approval of alternatives. For pipeline venting exemptions to these requirements, see section 6.2.
- g) Short-term vent gas emissions must not exceed the OVG limit set out in section 8.3.
- 4) The licensee or operator must notify residents and the appropriate AER field centre of nonroutine venting within 500 m and must comply with *Directive 056* in respect of providing information about continuous flaring, incinerating, and venting to persons entitled to it. Refer to section 3.8 for nonroutine venting notification requirements.
- 5) Vent gas must not constitute an unacceptable fire or explosion hazard and must comply with the spacing requirements in section 7.8. Venting must also not occur closer than
 - a) 25 m from any flame-type equipment (for diesel engines equipped with air intake shutoff device, see *Directive 036: Drilling Blowout Prevention Requirements and Procedures*),
 - b) 50 m from a wellhead for vent stacks other than surface casing vents, or
 - c) 25 m from a wellhead for heavy oil/bitumen well, storage tank, or other ignitable vapour including lined earth excavations used for waste oil storage.
- 6) A flame arrester or equivalent safety device, or proper engineering and operating procedures (e.g., sufficient sweep gas velocity) must be used on all vent lines connecting oil storage tanks to flare or incinerator stacks.
- 7) When equipment is used to control vent gas, the duty holder must design and operate control equipment to conserve or destroy at least 95 per cent of vent gas captured, with the equipment operating a minimum of 90 per cent of the time vent gas is emitted.

8.8 Requirements for Venting Gas Containing H₂S or Other Odorous Compounds

- 1) Gas containing more than 10 mol/kmol H₂S must not be vented to the atmosphere (excluding crude bitumen batteries). This includes gas off stock tanks, PSVs, and equipment blowdown systems.
 - a) Sour pressure-relief valves must be tied into flare systems if the gas contains more than 10 mol/kmol H₂S or result in off-lease H₂S odours.
- 2) At crude bitumen batteries, H₂S must not be vented to the atmosphere at a release rate greater than 0.04 m³/hr.
 - a) Sour pressure-relief valves must be tied into flare systems if the total H₂S release rate is greater than 0.04 m³/hr H₂S or results in off-lease H₂S odours.

- 3) Venting and/or fugitive emissions must not result in any H₂S odours outside the lease boundary. Venting and/or fugitive emissions must not result in any offensive hydrocarbon odours outside the lease boundary that, in the opinion of the AER, are unreasonable either because of their frequency, their proximity to surface improvements and surface development (as defined in *Directive 056*), their duration, or their strength.
 - a) The AER recommends that PSVs and blowdown systems be connected to a flare system where such systems are installed.
- 4) Venting must not result in exceedances of the *AAAQO* outside the lease boundary.
- 5) Pressurized tank trucks or trucks with suitable and functional emission controls must be used when transporting sour fluids from upstream petroleum industry facilities.

8.9 Noncombustible Vent Gas Requirements

Release of inert gases such as nitrogen and carbon dioxide from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases may be vented to atmosphere subject to the following requirement:

- 1) 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 dilution gas to ensure destruction of odorous compounds.

8.10 Fugitive Emissions Management

The requirements in this section apply only to sites with active wells or facilities that are outside of the Peace River area. For operations within the Peace River area, the duty holder is to follow the fugitive emissions requirements in *Directive 084*.

8.10.1 Fugitive Emissions Management Program

- 1) The duty holder must have a documented fugitive emissions management program (FEMP).
- 2) The FEMP must be designed to reduce fugitive emissions, contain the elements listed in appendix 12, and be updated to reflect any changes to operations.

The duty holder may be directed to carry out additional actions to manage fugitive emissions if the AER determines that they are needed to mitigate potential risks to the environment or safety.

For further information on FEMPs, see *Manual 016: How to Develop a Fugitive Emissions Management Program*.

8.10.2 Fugitive Emissions Surveys

The AER may conduct fugitive emissions surveys or screenings. Surveys conducted by the AER do not replace any survey the duty holder is required to complete. If the AER detects fugitive emissions, it will direct the duty holder to make repairs.

8.10.2.1 Frequency

- 1) The duty holder must conduct fugitive emissions surveys at the frequency specified in table 4.

The survey frequency for facilities is dictated by the facility subtype code, as set out in *Manual 011*, and not the equipment on site.

Facilities that are designed to vent all received and produced gas do not require fugitive emission surveys.

- 2) The duty holder may adjust survey frequency to align with operational visits at sites where access is restricted. The duty holder must provide justification for the adjusted survey frequency to the satisfaction of the AER, upon request.

Table 4. Frequency of fugitive emissions surveys by equipment or facility type

Equipment or facility type	Facility subtype codes ¹	Frequency
Sweet gas plants	401	Triannually
Compressor stations (<0.01 mol/kmol H ₂ S in inlet stream)	601, 621 ²	
Liquid hydrocarbon storage tanks with vent gas control	N/A	
Produced water storage tanks with vent gas control	N/A	
Gas plants	402, 403, 404, 405	Annually
Straddle and fractionation plants	406, 407	
Compressor stations (≥ 0.01 mol/kmol H ₂ S in inlet stream)	601, 621 ²	
Battery and associated satellite facilities ³	311, 321, 322, 331, 341, 342, 344, 345, 351, 361, 362, 363, 364	
Custom treating facilities	611, 612	
Terminals	671, 673	
Injection/disposal facilities	501, 502, 503, 504, 505, 506, 507	

¹ Facility subtype codes are from *Manual 011*.

² Subtype codes for compressor stations and gathering systems do not differentiate between sweet and sour gas processing. H₂S content of gas in the inlet stream determines the survey frequency for those facilities.

³ Wells linked to the facility subtype code but that are not located on the same site are excluded from the surveys.

8.10.2.2 Equipment and Methods

1) The duty holder must conduct fugitive emission surveys using one of the following:

- a) an organic vapour analyzer that detects hydrocarbons at a concentration of 500 ppm and is operated in accordance with the United States Environmental Protection Agency's (EPA's) Method 21: Determination of Volatile Organic Compound Leaks;
- b) a gas-imaging camera that can detect a stream of pure methane gas emitted at a rate of 1.0 gram per hour or less under controlled laboratory conditions and that is operated within six metres of the equipment being surveyed; or
- c) other equipment or methods that are equally capable of detecting fugitive emissions. However, the duty holder must assess equivalency and, upon request by the AER, demonstrate equivalence.

For further guidance on survey methods and equipment, see *Manual 016*.

8.10.2.3 Scope

- 1) The duty holder must survey the following:
 - a) equipment components with hydrocarbon throughput;
 - b) hydrocarbon gas-driven pneumatic devices;
 - c) tank-top equipment, including thief hatches and gauge-board assemblies;
 - d) surface casing vents and the area around the wellbore;
 - e) equipment used to destroy vent gas, including burners, flare ignitors, pilots, and combustors; and
 - f) equipment used to conserve vent gas, including vapour recovery units and vent gas capture systems.

8.10.2.4 Training and Equipment Maintenance

- 1) The duty holder must ensure that individuals conducting fugitive emission surveys are trained to use fugitive emissions survey equipment.
- 2) The duty holder must ensure that all equipment used to detect or quantify fugitive emissions is operated, serviced, and calibrated to the manufacturer's recommendations.

8.10.3 Fugitive Emissions Screenings

8.10.3.1 Frequency

- 1) The duty holder must ensure that annual fugitive emissions screenings are completed at all well sites except for
 - well sites that have been included in a fugitive emission survey that year,
 - well sites where all received and produced gas is vented, and
 - well sites with only oil sands evaluation wells or test holes approved under section 2.030 of the *OGCR*.

8.10.3.2 Methods and Equipment

- 1) The duty holder must conduct fugitive emissions screenings using one of the following:
 - a) audio, visual, or olfactory methods;
 - b) soap solution;
 - c) other methods or equipment that is capable of detecting fugitive emissions, such as unmanned aerial vehicles or truck mounted sensors; or
 - d) fugitive emissions survey methods and equipment.

For guidance on screening methods and equipment, see *Manual 016*.

8.10.3.3 Training

- 1) The duty holder must ensure that individuals completing fugitive emissions screenings are trained to identify common sources of fugitive emissions.

8.10.4 Repairs

- 1) The duty holder must repair sources of fugitive emissions or take other action to eliminate fugitive emissions within 24 hours of identification if fugitive emissions
 - a) are causing off-lease odours,
 - b) are the result of a failed pilot or ignitor on a flare stack, or
 - c) have the potential to cause safety issues.
- 2) The duty holder must repair all other sources of fugitive emissions or take other action to eliminate fugitive emissions within 30 days unless any of the following applies:
 - a) A major shutdown is required to complete the repair and there are no safety issues.
 - Repair at the next planned shutdown or as directed by the AER.
 - b) The fugitive emissions, measured using US EPA Method 21, have a hydrocarbon concentration less than 10 000 ppm.
 - No repair is required; however, these emissions must be quantified at each subsequent survey until the source is repaired.
 - c) The fugitive emissions are from surface casing vent flow or gas migration.
 - Manage in accordance with the timelines in *Directive 087: Well Integrity Management*.

8.10.4.1 Repair Confirmation

- 1) The duty holder must confirm the integrity of any repair within seven days of the component being brought back into service.

8.10.4.2 Tracking Sources of Fugitive Emissions for Repair

- 1) The duty holder must track the source of fugitive emissions for subsequent repair unless the repair is conducted immediately upon emissions detection.

The AER recommends that a duty holder physically tag a source that needs to be repaired and remove the tag once the integrity of the repair has been confirmed.

8.10.5 Reporting

- 1) The operator of record must include in the annual methane emissions report
 - a) the volume of fugitive emissions (m³) by facility ID, including any additional volume detected during an AER survey;

- b) the corresponding mass of methane emitted (kg) by facility ID; and
- c) for any fugitive emissions site survey, tank survey, or well screening during the reporting period,
 - i) the type of survey or screening (site survey, tank survey, or well screening),
 - ii) the date the survey or screening was completed (YYYY/MM/DD) per site by facility ID, and
 - iii) the number of identified sources of fugitive emissions per site by facility ID.

8.10.6 Alternative Fugitive Emissions Management Program

The AER will consider innovative and science-based alternatives to the fugitive emissions management program prescribed in this directive. Alternative programs may incorporate the use of various technologies such as unmanned aerial vehicles, vehicle-mounted sensors, and continuous monitoring devices to detect, track, repair, and report fugitive emissions.

- 1) If a duty holder wishes to use an alternative FEMP, the duty holder must submit a proposal to the AER for review and possible approval.
- 2) The duty holder must follow the requirements in sections 8.10.2 and 8.10.4 until its alternative program is approved.

8.11 Methane Emissions Record Keeping

- 1) Duty holders must retain records of the following for four years from the date they were created, unless otherwise noted, and provide them to the AER upon request:
 - a) Calculations, by site, used to determine the monthly volume and monthly mass of methane from each of the sources below:
 - defined vent gas,
 - instruments and pumps,
 - compressor seals,
 - glycol dehydrators, and
 - fugitive emissions.

In addition,

- the hours of equipment usage or activity rates used in the monthly calculations, and
- the supporting information, such as gas compositions, equipment test results, equipment or component numbers, gas density, conversion factors, and emission factors used in the monthly calculations.

If records are generated for compliance with *Directive 007: Volumetric and Infrastructure Requirements* or section 10 of this directive, the *Directive 007* records retention requirements and section 10 requirements supersede this requirement.

- b) For fugitive emissions,
 - i) the FEMP that is in effect,
 - ii) sites where access is restricted and the reason for the restricted access,
 - iii) completed training programs and valid certifications for all individuals conducting fugitive emission surveys and screenings, and
 - iv) survey and screening results containing the information set out in appendix 13.
- c) Inventory, updated annually, of pneumatic instruments and pumps that emit vent gas, including
 - i) tracking identifier or serial number,
 - ii) legal survey location (LSD-SC-TWP-RGWM) and facility ID,
 - iii) installation or modification date,
 - iv) make and model,
 - v) device type (categorize as pump, level controller, non-level controller),
 - vi) for level controllers that vent gas, the actuation frequency, and
 - vii) for instruments that are exempt under section 8.6.1.1, the reason for the exemption (safety or response time).
- d) Documentation that demonstrates that control equipment meets the requirements for vent gas control in section 8.7.
- e) The MRRCP that is in effect.
- f) For sites with first production or equipment installed before January 1, 2022, the dates of equipment changes for vent gas emissions management.
- g) The RCS fleet average vent gas rate calculations.
- h) Inventories of reciprocating and centrifugal compressors rated at least 75 kW, including
 - i) compressor frame serial number or other unique identifier,
 - ii) compressor power rating (kW),
 - iii) legal survey location (LSD-SC-TWP-RGWM) and facility ID,
 - iv) whether the equipment was installed before or after January 1, 2022,
 - v) licence number and licensee,

- vi) compressor type (reciprocating or centrifugal),
- vii) number of throws (if reciprocating),
- viii) seal type (dry or wet if centrifugal),
- ix) whether seal vent is controlled or uncontrolled,
- x) control device operating time, where applicable,
- xi) compressor seal change-out date,
- xii) the number of hours monthly a compressor was pressurized,
- xiii) compressor seal test results, in m³/hr,
- xiv) compressor seal test dates, and
- xv) the type of equipment used for the compressor seal test.

9 Sulphur Recovery Requirements and Sour Gas Combustion

Certain types of oil production, gas gathering, and nonassociated gas battery facilities can have significant sulphur emissions from combustion (by flaring, incinerating, or use as equipment fuel) of sour solution gas, from low-pressure produced water flash-gas, and from flaring of glycol dehydrator vent gas. Appropriate pollution prevention measures must be implemented in such situations to minimize sulphur emissions from combustion of sour or acid gas.

- 1) Guidelines in *ID 2001-03* apply to sour gas plants and other upstream petroleum facilities such as oil production batteries, gas batteries, and pipeline facilities.
- 2) For in situ bitumen sites, the sulphur recovery requirements in table 1 of *ID 2001-03* apply. The sulphur inlet used to determine the sulphur recovery requirement in table 1 is based on total sulphur emissions from combustion of sour produced gas as fuel or by flaring or incineration divided by the number of days over a calendar quarter-year.

9.1 Sulphur Recovery Exemption at Solution Gas Conservation Facilities

The AER and AEP may deviate from sulphur recovery requirements in circumstances where sulphur emissions would be minimal and sulphur recovery would render gas conservation uneconomic.

Solution gas conservation clustering schemes that have a total inlet sulphur of between 1 and 5 tonnes/day may be considered for flexibility by AEP and the AER in the application of *ID 2001-03*. Provisions for deviations from the sulphur recovery guidelines are in section 4 of *ID 2001-03*.

- 3) The licensee or operator must demonstrate to the AER, using the methodology in section 2.9, that implementing sulphur recovery would make the gas plant uneconomic.
 - a) If gas production with sulphur recovery is economic, the licensee or operator must implement sulphur recovery.
- 4) The licensee or operator must demonstrate that revenues and cost estimates are reasonable.
 - a) Capital cost estimates for sulphur recovery must be based on appropriate technologies. The licensee or operator must identify cost-effective processes suited to the facilities in question.
 - b) Information on the following must be available to the AER upon request:
 - i) volumes of gas available, including assessment of clustering other gas sources in the area
 - ii) incremental energy (e.g., fuel gas) requirements for gas compression and processing related to gas sweetening
 - iii) incremental energy (fuel gas) requirements for sulphur recovery processes

- iv) H₂S concentration of gas, along with expected average sulphur emissions and variability of sulphur emissions
 - v) information on technology selection and costs for equipment (e.g., compression), gas gathering systems, and sulphur recovery processes. Note that the economic evaluation is based on incremental costs of gas conservation; therefore, equipment costs related to oil production, processing, and transportation must not be included
- 5) The licensee or operator must consult with residents within the radius set out in *Directive 056*, specifically explaining that a variance of the sulphur recovery guidelines is being applied for. Any objections must be disclosed in related facility applications.
- 6) The AER and AEP will consider the scope of the production project, the duration of the sulphur emissions, and the views of the local public in making decisions on applying the sulphur recovery guidelines.
 - a) The existing processes used for *EPEA* approvals for sour gas processing plants and for AER approvals will be used to measure public acceptance of any proposals. If there are no unacceptable impacts and nearby residents do not object, meeting the sulphur recovery guidelines may not be required for solution gas facilities.
 - b) The AER does not allow multiple nonsulphur-recovery sour operating sites in close proximity where it is practical to consolidate the facilities in one location and install sulphur recovery.
 - i) Sour gas facility proliferation guidelines in *ID 2001-03*, section 6, stipulate how the AER will assess this matter.
- 7) The variances do not apply to sour gas production and processing facilities handling primarily nonassociated gas.

10 Measurement and Reporting

Requirements for measuring and reporting volumes of gas flared, incinerated, and vented are provided in *Directive 017: Measurement Requirements for Oil and Gas Operation*, *Directive 007: Volumetric and Infrastructure Requirements*, and the *OGCR*.

10.1 Flaring, Incineration, and Venting Records (Logs)

- 1) The licensee, operator, or approval holder must maintain a log of flaring, incineration, and venting events and respond to public complaints in order to comply with release reporting requirements.
 - a) Release reporting requirements are defined in *EPEA* and the [Release Reporting Regulation](#) clarified in the AEP's *A Guide to Release Reporting*.
 - b) Logs must include information on complaints related to flaring, incineration, and venting and how these complaints were investigated and addressed.
 - c) Logs must describe each nonroutine flaring, incineration, and venting incident and any changes made to prevent future nonroutine events from occurring.
 - d) Logs must include the date, time, duration, gas source or type (e.g., sour inlet gas, acid gas), rates, and volumes for each incident.
 - e) Logs must be kept for at least 12 months.
- 2) Flaring, incineration, and venting records must be made available to the AER upon request for each production facility, pipeline, and gas processing facility where flaring, incineration, and venting occur.
 - a) A licensee, operator, or approval holder may retain logs for remote or semi-attended facilities at a central location (e.g., a regional office) where public complaints related to the facility in question would normally be received.
- 3) In situations governed by temporary flaring/incineration permits, a sour gas flaring/incineration data summary report (see appendix 6) must be completed in full and submitted to the AER within three weeks of the flaring/incineration completion date.

Appendix 1 References and Contacts Cited

AER Documents*

Oil and Gas Conservation Rules

Directive 007: Volumetric and Infrastructure Requirements
 Directive 008: Surface Casing Depth Requirements
 Directive 017: Measurement Requirements for Oil and Gas Operations

Directive 036: Drilling Blowout Prevention Requirements and Procedures

Directive 037: Service Rig Inspection Manual

Directive 038: Noise Control

Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators

Directive 040: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices

Directive 055: Storage Requirements for the Upstream Petroleum Industry

Directive 056: Energy Development Applications and Schedules

Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs

Directive 066: Requirements and Procedures for Pipelines

Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry

Directive 087: Well Integrity Management

Interim Directive (ID) 91-03: Heavy Oil/Oil Sands Operations

ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta

AERflare.xls and AERincin.xls spreadsheets

AERflare: A Screening Model for Non-routine Flaring Approvals and Routine Flare Air Dispersion Modelling for Sour Gas Facilities

ABflare: A Refined Air Quality Dispersion Model for Evaluating Non-routine Flaring for Sour Gas Facilities

ST13A: Alberta Gas Plant/Gas Gathering System Activities—Annual Statistics

ST13B: Alberta Gas Plant/Gas Gathering System Activities—Monthly Statistics

ST13C: Alberta Gas Gathering System Activities—Monthly Statistics

ST60: Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data

ST60B: Upstream Petroleum Industry Flaring and Venting Report

Alberta Energy Document

Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program

Alberta Environment and Parks Documents

Air Quality Model Guideline

Alberta Ambient Air Quality Objectives and Guidelines
 Environmental Protection and Enhancement Act

Non-routine Flaring Management: Modelling Guidance
 Release Reporting Guideline 1028-F

Alberta Utilities Commission Document

Alberta Utilities Commission Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations

Other Documents

Alberta Pressure Equipment Safety Regulations, Alberta Safety Codes Act, The Pressure Equipment Safety Authority (AR 49/2006)

ANSI/API-521, Pressure-Relieving and Depressuring System, American Petroleum Institute

Clean Air Strategic Alliance (CASA), 1998, Management of Routine Solution Gas Flaring in Alberta, Report and Recommendations of the Flaring Project Team (Edmonton, Alberta)

CAPP, 2013, Sour Non-routine Flaring Framework

CAPP, 2006, Best Management Practices for Facility Flare Reduction

(continued)

* AER documents are available on the AER website at www.aer.ca and from AER Order Fulfillment, Suite 1000, 250 – 5 Street SW, Calgary AB T2P 0R4; telephone: 1-855-297-8311 (option 2); fax: 403-297-7040; email: InformationRequest@aer.ca.

Other Documents (continued)

CASA, 2002, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team (Edmonton, Alberta)

CASA, 2004, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Recommendations for Coal Bed Methane Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Review of Well Test Time Limits Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

Canadian Standards Association, 2016, CSA Z620.1: Fugitive and Vented Emissions for Petroleum and Natural Gas Industry Systems

Consumer Price Index forecast, Government of Alberta, Department of Finance website: www.finance.gov.ab.ca

Engineering and Geoscience Professions Act, RSA 2000 c. E-11

Forest and Prairie Protection Act, RSA 2000 c. F19

Forest and Prairie Protection Regulations Part I and II (AR 135/72)

GLJ Petroleum Consultants Limited, *Commodity Price Forecast*, “Natural Gas and Sulphur Price Forecast Table”

Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team, CASA

GPSA Engineering Data Book (13th edition), Gas Processors Suppliers Association

Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, CAPP

Industry Recommended Practice (IRP) Volume 4-2000/02: Well Testing and Fluid Handling, Canadian Petroleum Safety Council

United States Environmental Protection Agency (US EPA), Method 21: Determination of Volatile Organic Compound Leaks

PTAC Alberta Upstream Petroleum Research Fund Terms of Reference

AER Contacts

Customer Contact Centre: 403-297-8311

Field Centres

Bonnyville: 780-826-5352

Drayton Valley: 780-542-5182

Edmonton (formerly St. Albert): 780-642-9310

Grande Prairie: 780-538-5138

High Level: 780-926-5399

Medicine Hat: 403-527-3385

Midnapore: 403-297-8303

Red Deer: 403-340-5454

Wainwright: 780-842-7570

Regional Offices

Fort McMurray: 780-743-7214

Slave Lake: 780-843-2050

Appendix 2 Definitions of Terms as Used in *Directive 060*

acid gas	Gas that is separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H ₂ S), total reduced sulphur compounds, and/or carbon dioxide (CO ₂).
active facility	A facility that has reported an operation (volumetric activity) to Petrinex in the last 12 calendar months or is a nonproduction reporting facility linked to an active facility.
active well	A well that has reported an operation (production or injection) to Petrinex in the last 12 calendar months or is classified as an observational well by the AER.
associated gas	Gas that is produced from an oil or bitumen reservoir. This may apply to gas produced from a gas cap or in conjunction with oil or bitumen.
carbon conversion efficiency (cce)	The CCE quantifies the effectiveness of a device to oxidize hydrocarbons and is the relative conversion of carbon compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt hydrocarbons (hydrocarbon [HC] measured as methane [CH ₄]) and other partially oxidized carbon compounds, such as carbon monoxide (CO) in the exhaust. CCE is reported as the percentage of carbon in the fuel that is converted to CO ₂ and is obtained from

$$CCE = \frac{\text{Mass Rate of Carbon in the Fuel Converted to CO}_2}{\text{Mass Rate of Carbon in the Fuel}}$$

With this definition, the mass and molar efficiency are the same. An adjustment must be made if there is CO₂ in the inlet stream, as it does not react. The adjustment depends on the fraction of $CO_{2,fuel}$ and hydrocarbons $C_X H_{Y,fuel}$ in the gas stream entering the device and the number of carbon moles (X) per molecule of hydrocarbon. CCE can be determined from exhaust and fuel concentration measurements using

$$CCE = \frac{CO_{2,stack} - (CO_{2,fuel} / (X C_X H_{Y,fuel})) (CO_{stack} + HC_{stack})}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

This equation reduces to the following familiar expression if the inlet does not contain CO₂ (CO_{2,inlet} = 0):

$$CCE = \frac{CO_{2,stack}}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

clustering	The practice of gathering the solution gas from several flares or vents at a common point for conservation.
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combustion efficiency (ce)	The CE quantifies the effectiveness of a device to fully oxidize a fuel. Products of complete combustion (i.e., CO ₂ , H ₂ O, and sulphur dioxide [SO ₂]) result in all of the chemical energy released as heat. Products of incomplete combustion (e.g., CO, unburnt hydrocarbons, other partially oxidized carbon compounds, H ₂ S, and other reduced and partially oxidized sulphur compounds) reduce the amount of energy released. CE is reported as the percentage of the net heating value that is released as heat through combustion.
component	A piece of equipment that has the potential to release hydrocarbons. Components include valves, connectors, pump seals, actuator seals, flow meters, pressure regulators, sampling connections, instrument fittings, engine and compressor crankcase vents, sump and drain-tank vents and covers, blowdown system vents, open-ended valves and lines, pressure vacuum relief valves, and gauge-board assemblies.
condensate	Refer to <i>Oil and Gas Conservation Act</i> .
conservation	The recovery of solution gas for use as fuel for production facilities, other useful purposes (e.g., power generation), sale, or beneficial injection into an oil or gas pool.
conservation efficiency	Conservation efficiency (%) = $(\text{Solution gas production} - \text{Flared} - \text{Vented}) / (\text{Solution gas production}) \times 100$
conserving facility	Any potential tie-in point that is conserving gas, such as batteries, plants, compressor stations, pipelines, and pump stations.
control	For the purpose of section 8, means to conserve or destroy vent gas. Standards for when equipment is used to control gas are found in section 8.7.
crude bitumen	Refer to the <i>Oil and Gas Conservation Act</i> .
crude bitumen battery	A crude bitumen battery is an oil battery with crude bitumen production that has a density of 920 kg/m ³ or greater at 15 degrees Celsius.
crude oil	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or crude bitumen.
crude oil battery	An oil battery with crude oil production excluding production that has a density of 920 kg/m ³ or greater at 15 degrees Celsius.
defined vent gas	Vent gas from routine venting, excluding from pneumatic devices, compressor seals, and glycol dehydrators.

duty holder	In section 8, depending on the context, means the holder of an approval under the <i>Oil Sands Conservation Act</i> , the holder of a licence or approval under the <i>Pipeline Act</i> or <i>Oil and Gas Conservation Act</i> , or the operator of a facility where a licence or approval is not required under the <i>Oil and Gas Conservation Act</i> .
emergency flaring, venting, or incineration	Emergency flaring, venting, or incineration occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of possible causes of emergency flaring, venting, or incineration include pressure safety valve overpressure and emergency shutdown.
facility	Refer to the <i>Oil and Gas Conservation Act</i> .
facility id	As defined in <i>Directive 047</i> , a unique facility identification code, with 4 letters and 7 numbers (e.g., ABWP1234567), assigned by Petrinex to each facility.
flare gas	<p>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 (including an enclosed combustor), that must be reported as flare gas include the following:</p> <ul style="list-style-type: none"> • waste gas; • pilot gas; • dilution and makeup gas added to a flare gas stream before flaring or incineration; • acid gas (routine and nonroutine); • blanket gas, purge gas, and sweep gas; • gas used to operate pneumatic devices (pneumatic instruments, pumps, and compressors starters); • gas from dehydrator still columns; • gas produced during well completions; • gas produced during well unloading operations; and • gas that is flared or incinerated as a result of equipment failures or plant upsets.
fuel gas	<p>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:</p> <ul style="list-style-type: none"> • engines, • catalytic heaters and other building heaters, • process vessel burners, • sulphur recovery unit reaction furnaces, • line heaters, and • thermoelectric generators.
fugitive emissions	Unintentional releases of hydrocarbons to the atmosphere.

fugitive emissions screenings	Site-wide evaluations where the primary purpose is to identify fugitive emissions (e.g., from open thief hatches). These are less comprehensive than fugitive emission surveys.
fugitive emission surveys	Site-wide evaluations that use equipment-based methods to detect and identify sources of fugitive emissions for repair. These surveys are considered comprehensive evaluations that can assist in reducing both small volumes and large volumes of fugitive emissions.
gas battery	A system or arrangement of tanks and other surface equipment (including interconnecting piping) that receives the effluent from one or more wells that might provide measurement and separation, compression, dehydration, dew point control, H ₂ S scavenging where <0.1 tonne/day of sulphur is being treated, line heating, or other gas handling functions prior to the delivery to market or other disposition. This does not include gas processing equipment that recovers more than 2 m ³ /day of liquids or that processes more than 0.1 tonne/day of sulphur.
gas processing plant	A system or arrangement of equipment used for the extraction of H ₂ S, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m ³ /day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigerant, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of nonregenerative scavenging chemicals that generate no H ₂ S or SO ₂ .
makeup gas	Raw or processed gas that is added to another gas stream in order to maintain an adequate heating value during flaring or incineration.
measurement	A procedure for determining a value for a physical variable. This may include metering, testing, estimating, or calculating.
metering	To measure using a meter.
nonassociated gas	Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs or with production).
nonroutine flaring, venting, incineration	“Nonroutine” applies to intermittent and infrequent flaring, venting, or incineration. There are two types: planned and unplanned.
oil battery	A system or arrangement of tanks or other surface equipment or devices receiving the effluent of one or more wells for the purpose of separation and measurement prior to the delivery to market or other disposition.
operator	Refer to definition in the <i>Oil and Gas Conservation Act</i> .

operator of record	The person or organization that keeps records and submits production reports to Petrinex or the AER for a reporting facility ID, whether or not that person or organization is the sole licensee or approval holder for all facilities or wells that are part of that reporting facility ID.
planned flaring, venting, or incineration	Flaring, venting, or incineration where the operator has control over when and for how long it will occur and also has control over release rates. Planned flaring, venting, or incineration results from the intentional depressurization of processing equipment or piping systems. Planned flaring, venting, or incineration may occur during pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests.
pneumatic instrument	A pneumatic device, powered by pressurized gas, used for maintaining a process condition such as liquid level, pressure, or temperature. Includes positioners, pressure controllers, level controllers, temperature controllers, and transducers.
pneumatic pump	A pneumatic device that uses pressurized gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm. Includes methanol and chemical injection pumps, but does not include energy exchange pumps.
qualified technical professional	A person holding an accredited professional qualification and acting within that person's professional scope of practice.
risk-based criteria	Refer to AEP's <i>Non-Routine Flaring Management Modelling Guidance</i> for the purpose of <i>Directive 060</i> only.
routine flaring, venting, incineration	<p>"Routine" applies to continuous or intermittent flaring, venting, and incineration that occurs on a regular basis due to normal operation. Examples of routine flaring include glycol dehydrator reboiler still vapour flaring, tank vapour flaring, flash tank vapour flaring, and solution gas flaring. Routine venting can include gas from</p> <ul style="list-style-type: none"> • production casing vents, • process vents, • tank vents, • blanketing, • online gas analyzer purge vents, • pneumatic devices, and • desiccant dehydrator regeneration vents and membrane dehydrator purge vents.
schools	All public, private, and charter preschool, elementary, and secondary schools. This includes First Nations and Métis schools, but does not include a parent-provided home education program.

screening assessment	This is the quickest and simplest dispersion modelling approach. Screening assessments usually provide a conservative (worst-case) estimate of downwind concentrations. If exceedances of the <i>Alberta Ambient Air Quality Objectives and Guidelines</i> are predicted by a screening assessment, a refined assessment may be necessary. Alternatively, stack design parameters may be modified until predicted ambient air quality meets the <i>Alberta Ambient Air Quality Objectives and Guidelines</i> .
site	The area defined by the boundaries of a surface lease for upstream oil and gas facilities and wells (pads counted as one lease).
solution gas	All gas that is separated from condensate, oil, or bitumen production.
sour gas	Natural gas, including solution gas, containing H ₂ S.
source	All gas flared, incinerated, or vented from a single operating site, such as an oil battery or multiple-well pad.
sulphur conversion efficiency (sce)	<p>The SCE quantifies the effectiveness of a device to oxidize sulphur and is the relative conversion of sulphur compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt H₂S, other reduced sulphur compounds (measured as H₂S), such as carbonyl sulphide and carbon disulphide (especially if present in the fuel), and other partially oxidized sulphur compounds, such as sulphur trioxide (SO₃) in the exhaust (measured as SO₃). SCE is reported as the percentage of sulphur in the fuel that is converted to SO₂ and is obtained from</p> $SCE = \frac{\text{Mass Rate of Sulphur in the Fuel Converted to SO}_2}{\text{Mass Rate of Sulphur in the Fuel}}$ <p>With this definition, the mass and molar efficiency are the same. SCE can be determined from stack gas concentration measurements using</p> $SCE = \frac{SO_{2,stack}}{(SO_{2,stack} + SO_{3,stack} + H_2S_{stack})}$
sulphur emissions	All air emissions of sulphur-containing compounds, including SO ₂ , H ₂ S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO ₂ , with minor amounts of other compounds.
sulphur recovery efficiency	Sulphur recovery efficiency = (sulphur produced + injected)/(sulphur produced + injected + sulphur emissions), where the sulphur emission is normally SO ₂ expressed in sulphur equivalence. All values are units of mass.
throw	The parts of a reciprocating compressor from the connecting rod to the cylinder. The number of throws on a compressor is equal to the number of connecting rods off the compressor crankshaft.

unplanned flaring, venting, or incineration	Emergency or upset operational activities closely associated with protecting the integrity of the facility and protecting safety. The operator has no control over when these activities will occur. There are two types of unplanned flaring, venting, or incineration: upset and emergency.
upset flaring, venting, or incineration	Upset flaring, venting, or incineration occurs when one or more process parameters fall outside the allowable operating or design limits and flaring, venting, or incineration is required to aid in bringing the production back under control. Upset flaring, venting, or incineration may occur due to the production of off-spec product; the formation of hydrates; loss of electrical power; process upset; or operator error.
vent gas	<p>Uncombusted gas that is released to the atmosphere at upstream oil and gas operations. Vent gas does not include fugitive emissions, but does include</p> <ul style="list-style-type: none"> • waste gas; • gas used to operate pneumatic devices; • gas from compressor seals, starters, and blowdowns; • gas from facility upsets and emergency shutdowns; • gas from dehydrator still columns; • gas from production tanks, not including methanol and chemical tanks; • gas released during pigging operations; • gas produced during well completions; • gas produced during well unloading volumes; and • blanket gas.

Appendix 3 Abbreviations

10³ m³	thousand cubic metres
10⁶ m³	million cubic metres
AAAQO	Alberta Ambient Air Quality Objectives and Guidelines
AEP	Alberta Environment and Parks
AOF	absolute open flow
APEGA	Association of Professional Engineers and Geoscientists of Alberta
ASET	Association of Science and Engineering Technology Professionals of Alberta
AUPRF	Alberta Upstream Petroleum Research Fund
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CO₂	carbon dioxide
CSA	Canadian Standards Association
DVG	defined vent gas
EPAC	Explorers and Producers Association of Canada
EPEA	Environmental Protection and Enhancement Act
ESDV	emergency shutdown valve
FEMP	fugitive emissions management program
FIS	Field Information System
GOR	gas-to-oil ratio (gas-oil)
H₂S	hydrogen sulphide
HLSD	high-level shutdown
km	kilometre
kPa	kilopascal
mol/kmol	mole per kilomole
MJ	megajoule
MJ/m³	megajoule per cubic metre
MRRCPP	methane reduction retrofit compliance plan
MW	megawatt
NOWPP	New Oil Well Production Period
NPV	net present value
NRFTT	Non-routine Flaring Task Team
NTS	National Topographic System
OVG	overall vent gas
Petrinex	Canada's Petroleum Information Network
ppm	parts per million
PSV	pressure safety valve
PTAC	Petroleum Technology Alliance Canada
RCS	reciprocating compressor seal
SO₂	sulphur dioxide

Appendix 4 Background to *Directive 060*

Concerns about flaring prompted the Alberta Energy and Utilities Board (EUB; now the AER) and Alberta Environment (now Alberta Environment and Parks) to support Alberta Research Council research on flaring. Findings reported in 1996 suggested that the efficiency of flare stacks at destroying waste gas was not as high as originally thought and that various products of incomplete combustion were in flare emissions.

The EUB then consulted with stakeholders from industry, the public, and other government sectors and reviewed existing policies on solution gas conservation. CAPP brought the issue of flaring to the CASA board of directors in November 1996 and established the Flaring Project Team in February 1997 to develop recommendations to address potential and observed impacts of flaring. In its 1998 final report, *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team*, the Flaring Project Team recommended a framework for solution gas flaring management and a decision tree process for reducing flaring.

The EUB Implements the CASA Recommendations

In 1999 in the first edition of *Directive 060* (then called *Guide 60*), the EUB implemented the solution gas management framework (section 2), the decision tree process (section 2.3), and other CASA recommendations. The guide mandated firm, short-term solution gas flare reduction targets of 15 per cent and 25 per cent by the end of 2000 and 2001, respectively, relative to the 1996 revised baseline of $1340 \times 10^6 \text{ m}^3$ per year; the guide also defined maximum limits on the total volume of solution gas that could be flared at individual sites if voluntary targets were not met.

In 2000, a new CASA team, the Flaring/Venting Project Team, convened to review progress made on the 1998 recommendations as well as make further recommendations on flaring, incineration, and venting. The result was the 2002 report, *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team*. The report said that implementation of the solution gas management framework and the flare reduction targets by the upstream petroleum industry had successfully resulted in a 53 per cent reduction in solution gas flaring relative to the 1996 baseline.

On the basis of that success, the Flaring/Venting Project Team recommended that a similar decision tree process be applied to solution gas venting, well test flaring, and facility flaring. The team recommended that a 50 per cent reduction target be maintained for all solution gas flaring in Alberta relative to the 1996 baseline. Additional reports and recommendations were put forward in September 2004 and in March and June 2005. These recommendations were implemented through a rewrite of *Directive 060* released in November 2006. Significant changes included changing the economic threshold of the feasibility test for solution gas conservation from a net present value of zero to $-\$55\,000$. Also, economic evaluations were no longer required for sites that flared,

incinerated, or vented less than 900 m³/day of solution gas. Another significant addition to the directive was the concept of a duration limit for well test flaring and incineration.

Canadian Association of Petroleum Producers' Recommendations

In 2004, CAPP established the Nonroutine Flaring Task Team (NRFTT) to review dispersion modelling requirements for intermittent and infrequent flaring. The NRFTT comprised government and industry. The CAPP document titled, *Sour Non-Routine Flaring Framework* outlines the new regulatory approach and comprehensive plan for managing nonroutine flaring as developed by the NRFTT, and the process that led to its development.

Work on further reducing flaring, incineration, and venting continues.

Focus on Methane Emissions

In 2015, the Government of Alberta directed the AER to design and implement requirements that result in a 45 per cent reduction of methane emissions from the upstream oil and gas sector by 2025 from 2014 levels. In 2016, the AER created a multistakeholder committee to provide recommendations to the AER on regulating methane emissions in the province. The committee had representatives from the Government of Alberta, the AER, industry, and environmental non-governmental organizations.

With consideration of the recommendations from the committee, the AER developed methane emissions reduction requirements in *Directive 060*. The requirements cover both vent gas and fugitive emissions.

A mandatory review of the methane emissions requirements will occur within three years of the requirements taking effect to determine if any adjustments are needed.

Ongoing Research

The AER supports the 2004 CASA recommendations for additional research so that Alberta can continue to move towards the use of practical flare combustion efficiency standards where flaring is necessary. The AER expects that industry will support and participate in the funding of continued research focusing on

- understanding the relationship between gas composition and combustion efficiency, including the effects of H₂S content;
- understanding the effects of flare stack design, including flare tips on combustion efficiency;
- reviewing the results of any field testing of combustion efficiency monitoring methodologies;
- improving estimates of the amounts of methane emitted; and
- testing new technologies for emissions detection and reduction.

The AER supports the Petroleum Technology Alliance's Alberta Upstream Petroleum Research Fund (AUPRF). AUPRF is an industry-sponsored fund supported by CAPP and the Explorer and Producers Association of Canada (EPAC). The objective of AUPRF is to provide an efficient and effective mechanism to coordinate, initiate, fund, complete and communicate on environmental research that is needed by the industry and government regulators to enable a prosperous upstream oil and gas industry that achieves socially and environmentally responsible recovery of Canada's petroleum resources through effective, market-driven collaboration. AUPRF supports practical science-based studies that develop credible and relevant information to address knowledge gaps in the understanding and management of high priority environmental and social matters related to oil and gas exploration and development in Alberta. Research reports are shared broadly with the oil and gas industry as well as with regulators, government agencies, and other stakeholders.

Appendix 5 Permit Request for Flare or Incinerate Exceedance

This appendix includes the information for a permit request to flare or incinerate in exceedance of flared or incinerated volume allowance threshold (600, 400, or 200 10^3 m³ exceedance)

If flared or incinerated volumes are expected to exceed the volume allowance threshold during temporary operations, more information must be submitted to the AER.

- 1) Underbalanced drilling requests must include the following information:
 - a) an explanation and supporting documentation on how flaring or incineration rates are determined; possible sources of these estimates are
 - i) offset well AOF tests, or
 - ii) flaring or incineration rates from offset underbalanced drilling operations;
 - b) the estimated time required to drill the well;
 - c) if a well test is proposed, the total volume requested for the test.
- 2) For well tests that are expected to exceed the volume allowance threshold, the request must include the following information:
 - a) A brief description of the development required to bring the well onto production (e.g., length and size of pipeline to tie in well, well site facilities, compression, gas processing facilities)
 - b) The minimum recoverable reserves required for the well to be economic (minimum economic reserves)
 - c) Details of the analysis used to determine the minimum economic reserves. Licensees may use simplified “netback” economics showing the current operating profit (revenues minus operating costs) to estimate the recoverable reserves required to pay out facility investment costs; alternatively, licensees may choose to present a more detailed economic analysis involving features such as discounted gas flow projections)
 - d) The estimated recovery factor and surface loss for the pool
 - e) The estimated initial reservoir pressure
 - f) The amount of reservoir depletion being targeted by the test (the licensee must provide a brief description justifying this depletion in relation to the minimum economic reserve). The recommended maximum pressure depletion guidelines are
 - i) 1 per cent of the first 5000 kPa of reservoir pressure, and
 - ii) 0.5 per cent of the reservoir pressure above 500 kPa.

For example, a maximum depletion guideline of 100 kPa is targeted for a reservoir with an initial pressure of 15 000 kPa.

- g) Justification for pretest cleanup and servicing flaring or incineration if related volumes exceed $200 \times 10^3 \text{ m}^3$

Note that an incremental volume of up to $200 \times 10^3 \text{ m}^3$ may be added to the permit request in order to provide for pretest cleanup and servicing operations if these are needed to establish the minimum economic reserve without additional justification.

Appendix 6 Sour Gas Flaring/Incineration Data Summary Report

The form is available at Regulating Development > Rules and Directives > AER Forms > Directive Forms > *Directive 060* > [Appendix 6](#).

Appendix 7 Air Quality Management Plans for Temporary SO₂ Emissions

If exceedances of the risk-based criteria for SO₂ (see appendix 8) are predicted and it is not proposed that flare/incinerator design parameters be altered to mitigate the potential exceedances, approval may be granted by the AER if suitable control measures are in place. In such situations, an air quality management plan must be submitted with the temporary permit request. **The management plan must outline how predicted exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* will be avoided so that the risk-based criteria are met.**

The air quality management plan may include the following:

- 1) Restrictions during specific meteorological conditions that will limit or avoid operations under conditions that result in predicted exceedances.
 - a) These atmospheric conditions may include
 - i) time of day,
 - ii) wind direction,
 - iii) wind velocity, and
 - iv) atmospheric stability.
 - b) Meteorological monitoring may be used as a management plan based on a maximum one-hour rolling (i.e., any consecutive 60 minutes), with measurements taken at a frequency of no more than every 15 minutes (i.e., four measurements/hour).
- 2) The management plan must include specifications for locating meteorological monitoring equipment (if used). Wind monitoring devices must be elevated above the height of trees surrounding the site.
- 3) Restrictions that may be applied during unfavourable meteorological conditions.
 - a) Operational restrictions in air quality management plans may include
 - i) suspension of flaring or incineration operations,
 - ii) reduction or increase of flaring or incineration rates, and
 - iii) requirements that supplemental fuel gas meet a minimum heating value or exit velocity.
- 4) If a reduction in flaring or incineration rate or an addition of supplemental fuel gas is proposed, compliance with the risk-based criteria must be demonstrated with appropriate dispersion modelling results. (Note that reduced flaring or incineration rates do not result in a proportional reduction in predicted concentrations.)

- 5) Ambient air monitoring (mobile and/or stationary) must be located where exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* are predicted.
 - a) Ambient air monitoring in conjunction with appropriate flaring/incineration management procedures will only be accepted when it can be demonstrated that monitors can be placed in a manner that is reasonably protective of all locations where exceedances of the risk-based criteria are predicted. Stationary monitors are currently accepted to cover an arc of 22.5°C centred on the source. The licensee or operator must provide an NTS map of the area (1:50 000) indicating the locations of the stationary monitors and a table with the coordinates (i.e., Universal Transverse Mercator [UTM]). In cases where monitoring is proposed, a licensee or operator must demonstrate that there is good access to all areas with predicted exceedances *before* a request is submitted.
 - b) The *Alberta Ambient Air Quality Objectives and Guidelines* must not be exceeded, based on a one-hour average. To accomplish this, ambient air monitoring must occur at intervals of 15 minutes or less. **If the 30-minute average exceeds the *Alberta Ambient Air Quality Objectives and Guidelines*, the flaring or incineration operation must be immediately shut in.**
- 6) If there is more than one meteorological condition that requires a management response, or if a combination of meteorological restrictions and ambient air monitoring is proposed, the management plan must be summarized in a flowchart that is clear and concise and can be applied by on-site staff during flaring or incinerating operations. Furthermore, if multiple flow rates are proposed in the management plan, the risk-based criteria must be met for each flow rate.
 - a) The management plan must clearly specify the frequency at which the meteorological or ambient air quality monitoring data will be monitored by on-site staff. An averaging time of no more than 15 minutes is mandatory, as this allows for observations of trends and provides enough time to respond to elevated concentrations.
- 7) The management plan must clearly define under what conditions flaring or incineration may resume if suspended or may return to normal operations if a management option such as fuel gas is proposed. Flaring or incineration must remain suspended for at least one hour before operations may resume in order to prevent an exceedance or to respond to an exceedance.
 - a) Flaring or incineration may begin again after one hour or after meteorological conditions change and remain favourable for 30 minutes, whichever is longer.
- 8) Real-time dispersion modelling flare management plans must be based on maximum predicted concentrations. Pseudo input parameters must be calculated using AERflare. If real-time dispersion modelling goes down, the operator must revert to a conventional flare management plan or shut in.

Appendix 8 Screening Dispersion Modelling Using AER Spreadsheet

The AER sour well test flaring and incineration permit spreadsheets and technical descriptions are available on the AER website www.aer.ca under Regulating Development > Rules & Directives > Directives > Directive 060. They provide a screening analysis of the SO₂ and H₂S dispersion from permanent and temporary flares and incinerators. If the screening level maximum concentration predictions in parallel and complex airflow terrain for a source meet the *Alberta Ambient Air Quality Objectives and Guidelines (AAAQO)*, no further analysis is required. The spreadsheet can be submitted in support of the dispersion modelling assessment.

Maximum predictions for routine sources must meet the *AAAQO*. Due to the short-term nature of temporary nonroutine sources, risk-based criteria can be applied. The risk-based criteria apply to well tests and other temporary nonroutine flaring and incineration events. For further information about the spreadsheet refer to the AER flare User Guide: A Screening Model for Non-routine Flaring Approvals and Routine Flare Air Dispersion Modelling for Sour Gas Facilities.

If it is not practical to modify flare or incinerator design parameters, you may consider evaluating the proposed design with more refined dispersion modelling approaches. Additional refined dispersion modelling is required if the screening level maximum concentration predictions in parallel and complex airflow terrain for a source do not meet the *AAAQO*. A refined dispersion modelling assessment must meet AEP's *Air Quality Model Guideline* (2013) or *Non-Routine Flaring Management: Modelling Guidance* (2013).

For routine flaring, a refined dispersion modelling assessment is also required if there are continuous SO₂ emission sources within 10 km of the location or within the isopleth of one-third of the *AAAQO* for SO₂ (as described in section 7.12.3), whichever distance is less. This requires that the cumulative effects of the proposed flaring or incineration be assessed in combination with other sources.

A licensee, operator, or approval holder is responsible for ensuring that appropriately trained and qualified personnel complete the air quality evaluations.

A refined dispersion modelling assessment must include the following:

- 1) A description of the meteorological data source (location, years, and months). For models that require meteorological data, five years of meteorological data from a standard period is recommended. Three months per year must be modelled from the data set centred about the month of the requested permit date. The acceptable data sets are posted on the AEP website at <http://aep.alberta.ca/air/modelling/meteorological-data-for-dispersion-models.aspx>. Additional information about modelling and meteorological data requirements is on the AEP website.
- 2) A wind rose (a representation of the history of wind directions and wind speeds).

- 3) Refined modelling source parameters for maximum flow rate (Q_{\max}), average flow rate (Q_{avg}), and one-eighth maximum flow rate ($Q/8$) from the spreadsheet.
- 4) A summary of the model input parameters (a printed copy of the input file is preferred, as output files may be large and need not be submitted).
- 5) The maximum predicted one-hour ambient air SO_2 concentration for maximum flow rate (Q_{\max}), average flow rate (Q_{avg}), and one-eighth maximum flow rate ($Q/8$).
- 6) If exceedances of the one-hour *AAAQO* for SO_2 are predicted, a histogram of the overall probability of exceedance based on meteorological data is to be calculated, as follows, by dividing the number of hours with predicted exceedances by the total number of hours used in the meteorological data set:

$$\text{Probability of exceedance} = \frac{(\text{Cumulative number of hours with predicted exceedances})}{(\text{Total hours modelled})}$$

- 7) An interpretation of the modelling results (output files or model result printouts may be included if not excessively large).
- 8) Histograms showing exceedances based on criteria (e.g., wind direction, wind speed, and stability class).

If the risk-based criteria are not met, a management plan (see appendix 7) must be developed to achieve the risk-based criteria. Requests with management plans must include enough information so that the AER can assess the management plan, including

- 1) for each flow rate, a summary table of output, including
 - meteorological conditions (stability class and range of wind speeds and directions) or times of day that result in predicted exceedance of the one-hour *AAAQO* for SO_2 ,
 - maximum predicted SO_2 concentration for each condition where exceedances are predicted, and
 - the expected overall probability of exceedances before and after implementation of the management plan;
- 2) for each flow rate, an area map showing
 - locations of predicted SO_2 ground-level concentration isopleths (with a minimum 10 km radius) in excess of the one-hour *AAAQO* for SO_2 ,
 - sectors with flaring restrictions (if proposed),
 - locations accessible with a mobile monitoring unit (if proposed),
 - approximate location of proposed stationary monitors (if proposed) and, if available, a recent air photo showing the approximate location of proposed stationary monitors, as well

as specifications of the monitor location in a format usable by the monitoring licensee, operator, or approval holder (e.g., UTM coordinates or latitude and longitude), with an acceptable offset distance if this is required to improve access or telemetry line of site; site reconnaissance must be conducted before submission to ensure that monitors can be placed, and

- UTM coordinates of stationary monitors, as well as distance and direction from well;
- 3) a calculation of makeup gas requirements as a percentage of the produced gas being combusted (gas may be used to increase plume rise; care should be taken to minimize gas waste); and
 - 4) electronic copies (i.e., Microsoft Word or Excel files) of the management plan and decision tree (if applicable).

The AERflare.xls and AERincin.xls spreadsheets also evaluate minimum and maximum exit velocities with respect to downwash criteria. The results will help the licensee, operator, or approval holder optimize flare and incinerator design and verify parameters used for temporary flaring and incineration permit requests.

- 1) If downwash is predicted, the spreadsheet source parameters will conservatively account for downwash; however, it is recommended that the stack design parameters (e.g., stack diameter) be modified to avoid downwash.
- 2) The spreadsheet provides maximum and minimum exit diameters based on the recommended exit velocities. You must size the exit diameter within the range of exit diameters provided in AERflare.xls. Exit diameter is a permitted parameter. A qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*²² must review the design parameters.

The licensee, operator, or approval holder may submit data based on modified modelling methods for consideration; however, results from one of the accepted unmodified models must also be submitted for comparison. Description and scientific justification of the modifications must be provided. Generally, review of permit requests that use a modified modelling method requires more time, and the AER may accept or reject the modified results at its discretion.

²² *Engineering and Geoscience Professions Act* RSA 2000 c. E-11, as amended.

Appendix 9 Resident Flaring/Venting/Incinerating Notification Sample Form

We will be flaring/incinerating/venting a (___ % H₂S) well in accordance with AER *Directive 060* at the location stated below.

Flaring/Incinerating/Venting Category (check those that apply)	AER Office (check one)
Well test flaring	Bonnyville (780-826-5352)
Well test venting	Drayton Valley (780-542-5182)
Well test incinerating	Grande Prairie (780-538-5138)
	Fort McMurray (780-743-7214)
(Check one)	High Level (780-926-5399)
Oil well	Medicine Hat (403-527-3385)
Gas well	Midnapore (403-297-8303)
	Red Deer (403-340-5454)
	Slave Lake (780-843-2050)
	Edmonton – formerly St. Albert (780-460-3800)
	Wainwright (780-842-7570)
Flaring/Venting/Incinerating Comments	
Well Licence No.	
Well Name	
Location of Well (LSD)	
Estimated Flare/Incinerate/Vent Timing (30-day window)*	
Estimated Start Date	
Estimated End Date	
Flaring/Incinerating/Venting Duration	
Estimated Volume (10 ³ m ³ /day)	
Licensee or Operator Name	
Licensee or Operator Representative	
Contact Phone Number	
Testing Contractor	
Testing Representatives on Site	
Daytime Cell Phone Number	
Nighttime Cell Phone Number	
Emergency Phone Number	

Please phone (____) ____ - _____ if you would like notification 24 or 48 hours in advance of flaring/incinerating/venting operations.

- 30-day window is to accommodate for weather and operational delays.
- Renotification is mandatory after 90 days.

Note: _____

If you have questions or concerns, please phone (____) ____ - _____

Appendix 10 Agreement on Zero Flaring and Venting Agreement

The following serves to outline the agreement between _____ (applicant) and _____ (landowner or occupant) respecting flaring at the well located at _____ W _____. The applicant agrees to not flare from the well before putting the well on production except as stated below in this agreement or in an emergency. Venting is not to be used as an alternative to flaring.

Exceptions

Flaring may occur as indicated below and is limited to at most two of the activities:

- Well testing Yes? ____ No? ____
- Well cleanup Yes? ____ No? ____
- Drillstem testing Yes? ____ No? ____

Emergencies

The licensee, operator, or approval holder may flare in emergency situations for safety of the public or environmental protection.

If the ownership of the well is transferred to another licensee, operator, and/or approval holder, this agreement will remain in effect for the new licensee, operator, or approval holder and it is the licensee, operator, or approval holder's responsibility to advise any successors of this agreement.

This agreement no longer applies once this well is tied into a production facility or once production operations begin.

Applicant Signature _____	Landowner or Occupant Signature (optional) _____
Printed Name _____	Printed Name _____
Licensee, operator, or approval holder _____	
Location _____	
Telephone _____	Telephone _____
Email/Fax _____	Email/Fax _____
Date _____	

Appendix 11 Request to Extinguish Sour Gas Flare Pilots

The following minimum requirements must be met in any situation where it is proposed to extinguish a flare pilot at a sour facility:

- 1) The maximum stabilized wellhead pressure must be determined based on the measured stabilized static wellhead pressure corrected for the hydrostatic head of any liquid present in the wellbore at the time of testing.
 - a) This correction for the liquid column hydrostatic head must use the density of the produced water for the entire fluid column present in the wellbore.
 - b) The maximum stabilized static wellhead pressure must be determined by a qualified well test professional using accepted engineering practices. AER *Directive 040* provides regulations for conducting pressure tests on wells.
- 2) The following features must be incorporated into the facility for consideration of the request to extinguish the flare pilot:
 - a) Nonfragmenting rupture disks must be installed on the upstream side of all pressure safety valves (PSVs). This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association.
 - A pressure gauge or suitable telltale indicator must be installed between each rupture disk and the corresponding PSV to allow detection of leakage or a disk rupture.
 - b) Two block valves in series must be installed for manual depressurizing valves connected to the flare.
 - c) The battery must be equipped with a pressure sensor, automatic emergency shutdown valves (ESDVs), and a control system configured to isolate the battery from the well and outlet gas pipeline. There must be no automatically controlled emergency depressurizing valves connected to the flare.
- 3) Upstream piping to the well must be designed for the maximum pressure that might be encountered. The *minimum* operating requirements for any facility approved for extinguishing flare pilots include the following:
 - a) The licensee, operator, or approval holder must monitor and document on a weekly basis the pressure between rupture disks and PSVs.
 - b) If a rupture disk fails or if odours result from gas released to the flare stack, the flare stack must be lit and immediate notification must be given to the appropriate AER field centre, followed by a written incident report giving particulars. Approval to extinguish the flare pilot is then considered void until the licensee, operator, or approval holder demonstrates to

the satisfaction of the appropriate AER field centre that related problems have been successfully corrected.

- c) The sweet gas or propane pilot must be ignited prior to any flaring or depressurizing at the site.
 - d) The operation of the emergency shutdown system, including ESDVs, must be verified and documented at least once a year.
 - e) AER approval to extinguish the flare pilot must be visibly displayed at each site.
- 4) Residents within the emergency planning zone (EPZ) must be notified of plans to extinguish the flare pilot.
- 5) The following information must accompany the licensee's, operator's, or approval holder's request to extinguish flare pilots:
- a) a list of all wells connected to the battery, including
 - i) normal wellhead operating pressure, and
 - ii) maximum stabilized static wellhead pressure;
 - b) the maximum design operating pressure of the piping and pressure vessel systems for the battery, including
 - i) a list of all PSVs connected to the flare and related release set-pressures, and
 - ii) a list of related rupture disks and burst pressures;
 - c) written confirmation that
 - i) none of the wells connected to the facility are completed in pools that have active injection or cycling schemes,
 - ii) rupture disks on PSVs and two valves in series have been installed on all streams tied into the flare system,
 - iii) maximum H₂S release rates will not exceed the level-1 or -2 sour well classification,
 - iv) residents within the EPZ have been notified, and
 - v) high-pressure shutdowns are in place, with a statement confirming calibration frequency.

Appendix 12 Mandatory Elements of a Fugitive Emissions Management Program

The following elements are to be included in the FEMP:

- 1) Contact information of the individual accountable for the FEMP.
- 2) Resources allocated to developing and implementing the FEMP. Include which group within the company is responsible for maintaining and updating the FEMP and who (e.g., corporate environmental or operations group, third party) will be conducting the surveys and screenings.
- 3) Preventive maintenance practices to reduce or prevent fugitive emissions.
- 4) The procedures and plans that will be used to meet the required frequency of fugitive emissions surveys and screenings and to complete repairs. Indicate any deviations from the prescribed frequency and provide justification.
- 5) Techniques and equipment used for fugitive emissions surveys and screenings. Include equipment make and model and any plans to use alternative technologies.
- 6) Calibration methods and equipment maintenance practices for equipment used for fugitive emissions surveys.
- 7) Training programs and certification completed by individuals conducting fugitive emissions surveys or screenings.
- 8) Description of how individuals will be trained and how often they will be retrained or recertified.
- 9) Internal procedures to track, manage, and verify the status of repairs.
- 10) Data management practices and systems to ensure that survey and screening results trigger required repairs and that the repairs are captured for annual reporting.
- 11) Provisions for continuous improvement of the FEMP, including how FEMP data will be used to evaluate program performance.

Appendix 13 Fugitive Emissions Record Keeping

The form is available at Regulating Development > Rules and Directives > AER Forms > Directive Forms > *Directive 060* > [Appendix 13](#).